

THIS FILING IS

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

Form 1 Approved  
OMB No.1902-0021  
(Expires 12/31/2019)  
Form 1-F Approved  
OMB No.1902-0029  
(Expires 12/31/2019)  
Form 3-Q Approved  
OMB No.1902-0205  
(Expires 12/31/2019)



# FERC FINANCIAL REPORT

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

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

**Exact Legal Name of Respondent (Company)**

Northern States Power Company (Minnesota)

**Year/Period of Report**

**End of** 2016/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.)

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

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

"In connection with our regular examination of the financial statements of \_\_\_\_\_ 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 18<sup>th</sup> 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 1,144 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 150 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 filed..."

### **General Penalties**

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

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 <u>2016/Q4</u>	
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 (612) 330-5658	09 This Report Is (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		10 Date of Report (Mo, Da, Yr) 04/10/2017

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 Jeffrey S. Savage	03 Signature  Jeffrey S. Savage	04 Date Signed (Mo, Da, Yr) 04/10/2017
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.

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	N/A
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	N/A
25	Unrecovered Plant and Regulatory Study Costs	230	
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	N/A
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

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".

Line No.	Title of Schedule  (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	N/A
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	N/A
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	N/A
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	
65	Pumped Storage Generating Plant Statistics	408-409	N/A
66	Generating Plant Statistics Pages	410-411	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report End of <u>2016/Q4</u>
---	---	--	--

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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	

**Stockholders' Reports** Check appropriate box:

- Two copies will be submitted
- No annual report to stockholders is prepared

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report End of <u>2016/Q4</u>
---	---	--	--

**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 coporation) 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 2016, 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)  No

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report <i>(Mo, Da, Yr)</i> 04/10/2017	Year/Period of Report End of <u>2016/Q4</u>
---	---	---	--

**CONTROL OVER RESPONDENT**

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

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

**CORPORATIONS CONTROLLED BY RESPONDENT**

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

**Definitions**

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	NSP Nuclear Corp	Holds NSP's interest in	100	
2		Nuclear Mgmt Co. LLC		
3	Nuclear Mgmt Co. LLC	Manages nuclear power plants	100	
4	Private Fuel Storage, LLC	Nuclear waste storage	32.8	
5	United Power and Land Co.	Real estate holdings	100	
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				

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	Chairman of the Board, Chief Executive Officer	Ben Fowke	550,828
2	President	Christopher B. Clark	320,000
3	Executive Vice President	Marvin E. McDaniel, Jr.	221,692
4	Executive Vice President	Kent T. Larson	205,065
5	Executive Vice President, General Counsel	Scott M. Wilensky	203,403
6	Executive Vice President, Chief Financial Officer	Robert C. Frenzel	160,223
7	Executive Vice President, Chief Financial Officer	Teresa S. Madden	112,319
8	Senior Vice President, Chief Nuclear Officer	Timothy J. O'Connor	490,000
9	Senior Vice President, Corporate Secretary	Judy M. Pofert	126,067
10	Senior Vice President, Controller	Jeffrey S. Savage	116,892
11	Vice President, Treasurer	Brian J. Van Abel	100,769
12			
13	Salaries represent NSP-Minnesota's allocation of		
14	officers' salaries greater than \$50,000 for the period		
15	of time that was served as an officer for		
16	NSP-Minnesota.		
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
42			
43			
44			

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

**Schedule Page: 104 Line No.: 6 Column: a**

Robert C. Frenzel was elected Executive Vice President and Chief Financial Officer effective May 3, 2016.

**Schedule Page: 104 Line No.: 7 Column: a**

Teresa S. Madden resigned as Executive Vice President and Chief Financial Officer effective May 3, 2016.

**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 Vice President, CFO	414 Nicollet Mall, Minneapolis, MN 55401
3	Teresa S. Madden, Executive Vice President, CFO	414 Nicollet Mall, Minneapolis, MN 55401
4	Christopher B. Clark, President	414 Nicollet Mall, Minneapolis, MN 55401
5	Marvin E. McDaniel, Jr., Executive Vice President	414 Nicollet Mall, Minneapolis, MN 55401
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46		
47		
48		

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

**Schedule Page: 105 Line No.: 2 Column: a**

Robert C. Frenzel was elected Executive Vice President and Chief Financial Officer effective May 3, 2016.

**Schedule Page: 105 Line No.: 3 Column: a**

Teresa S. Madden resigned as Executive Vice President and Chief Financial Officer effective May 3, 2016.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report End of 2016/Q4
---	---	--	---

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

Does the respondent have formula rates?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No
---	--

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

Line No.	FERC Rate Schedule or Tariff Number	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 31, 2007, Accession No.
5		20071221-3012
6		
7	FERC Electric Tariff, Third Revised Volume No. 1	ER10-541-000 - Approval of Tariff Revisions to
8	(Midwest Independent Transmission System	Attachment O-NSP, Issued February 26, 2010,
9	Operator, Inc. Open Access Transmission and	Accession No. 20100226-3041
10	Energy Markets Tariff, Attachment O-NSP)	
11		
12	FERC Electric Tariff updated effective 01-01-2012	ER12-297-000 - Approval of Tariff Revisions to
13	(Midwest Independent Transmission System	Attachment O-NSP, Issued December 31, 2011,
14	Operator, Inc. Open Access Transmission and	Accession No. 201111221-3033
15	Energy Markets Tariff, Attachment O-NSP)	
16		
17	FERC Electric Tariff updated effective 01-01-2013	ER13-674-000/001/002 Approval of Tariff Revisions
18	(Midwest Independent Transmission System	to Attachment O-NSP, Issued March 20, 2013,
19	Operator, Inc. Open Access Transmission and	Accession No. 20130320-3014
20	Energy Markets Tariff, Attachment O-NSP)	
21		
22	FERC Electric Tariff updated effective 01-01-2013	ER14-421-000/001 Approval of Tariff Revisions
23	(Midwest Independent Transmission System	to Attachment O-NSP, Issued March 11, 2014,
24	Operator, Inc. Open Access Transmission and	Accession No. 20140311-3041
25	Energy Markets Tariff, Attachment O-NSP)	
26		
27	FERC Electric Tariff updated effective 01-06-2015	ER15-358-000/001 Approval of Tariff Revisions
28	(Midwest 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	(Midwest 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 01-01-2016	ER17-305-000 Approval of Tariff Revisions
38	(Midwest 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)	
41		

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report End of 2016/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)?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> 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					01-01-2016 (Midcontinent Independent
3					System Operator, Inc. Open
4					Access Transmission and Energy
5					Markets Tariff, Attachment O-NSP)
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/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.

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 Dfrd Debits		(c) 57
2	204	Electric Plant in Service (Acct 101, 102, 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 of Elect Util Plant (Acct 108)		(c) 20-26,28
6	227	Materials and Supplies		(a) 18
7	234	Accumulated Deferred Income Taxes (Acct 190)		(c) 8
8	267	Accum. Deferred Investment Tax Credits (Acct 225)		(h) 8
9	269	Other Deferred Credits (Acct 253)		(d), (e) 35
10	269	Other Deferred Credits (Acct 253)		(a) 44
11	272	Accumulated Deferred Income Taxes (Acct 281)		(b) 8
12	274	Accumulated Deferred Income Taxes (Acct 282)		(b) 2
13	276	Accumualted Deferred Income Taxes (Acct 283)		(b) 3
14	300	Electric Operating Revenues (Acct 400)		(b) 19
15	310.1	Sales for Resale (Acct 447)		(a) 13
16	321	Electric Operation and Maintenance Expenses		(b) 112
17	328	Transmission of Electricity for Others		(a) 19
18	356.2	Common Utility Plant and Expenses		n/a n/a
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report 04/10/2017	Year/Period of Report End of <u>2016/Q4</u>
---	---	------------------------------	--

**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: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

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

City	State	Utility	Expiration
Centerville	Minn.	Electric	Feb. 1, 2036
Centerville	Minn.	Gas	Feb. 1, 2036
Burnsville	Minn.	Electric	Feb. 15, 2036
Avon	Minn.	Electric	May 1, 2036
Horace	N.D.	Gas	May 1, 2036
Rice	Minn.	Electric	May 1, 2036
Belle Plaine	Minn.	Electric	May 15, 2036
Montrose	Minn.	Gas	Aug. 7, 2036
Sartell	Minn.	Electric	Sept. 11, 2036
Sartell	Minn.	Gas	Sept. 11, 2036
St. Louis Park	Minn.	Electric	Sept. 18, 2036
Lakeland Shores	Minn.	Electric	July 6, 2036
Victoria	Minn.	Electric	Oct. 9, 2036
Shakopee	Minn.	Gas	Oct. 31, 2036
Edgerton	Minn.	Electric	Dec. 6, 2036

**2. Acquisitions**

None

**3. Purchase or sale of an operating unit or system**

None

**4. Important leaseholds acquired or given, assigned or surrendered**

None

**5. Important extension or reduction of transmission or distribution system**

None

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

See Note 3 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 – Merit base increases ranging from 1.50 - 2.50 percent effective Jan. 1, 2016.

Non-Union Employees – Merit base increase of 3.00 percent effective March 16, 2016.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

**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, 2016, Teresa S. Madden resigned as Executive Vice President and Chief Financial Officer  
Effective May 3, 2016, Robert C. Frenzel was elected Executive Vice President and Chief Financial Officer

**14. Cash management programs**

Not applicable as proprietary capital ratio is greater than 30%

**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)
<b>1</b>	<b>UTILITY PLANT</b>			
2	Utility Plant (101-106, 114)	200-201	19,263,104,804	18,298,081,598
3	Construction Work in Progress (107)	200-201	509,028,925	548,033,874
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		19,772,133,729	18,846,115,472
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	7,413,415,120	6,940,949,706
6	Net Utility Plant (Enter Total of line 4 less 5)		12,358,718,609	11,905,165,766
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202-203	205,525,449	148,727,046
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		526,657,578	525,918,125
10	Spent Nuclear Fuel (120.4)		1,839,587,125	1,772,605,603
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	2,180,635,866	2,063,654,320
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		391,134,286	383,596,454
14	Net Utility Plant (Enter Total of lines 6 and 13)		12,749,852,895	12,288,762,220
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
<b>17</b>	<b>OTHER PROPERTY AND INVESTMENTS</b>			
18	Nonutility Property (121)		13,264,783	13,167,811
19	(Less) Accum. Prov. for Depr. and Amort. (122)		10,689,874	8,606,540
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	2,573,107	2,553,060
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)		44,297,238	34,057,691
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		1,861,011,461	1,724,399,969
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		24,678,410	22,333,814
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		1,935,135,125	1,787,905,805
<b>33</b>	<b>CURRENT AND ACCRUED ASSETS</b>			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		15,842,241	22,170,934
36	Special Deposits (132-134)		0	250,000
37	Working Fund (135)		124,640	128,040
38	Temporary Cash Investments (136)		31,490,417	20,183,604
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		310,862,746	278,196,766
41	Other Accounts Receivable (143)		77,639,403	48,366,355
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		19,967,629	20,750,400
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		51,390,452	44,239,696
45	Fuel Stock (151)	227	100,686,129	107,654,333
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	213,287,451	200,142,370
49	Merchandise (155)	227	942,563	738,863
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	4,067	6,628

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report End of 2016/Q4
---	---	--	---

**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)		24,872,348	28,936,798
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		5,399,564	6,436,816
57	Prepayments (165)		54,995,859	60,091,770
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		708,269	728,876
61	Accrued Utility Revenues (173)		259,590,461	227,101,551
62	Miscellaneous Current and Accrued Assets (174)		89,560	2,352,888
63	Derivative Instrument Assets (175)		46,706,476	41,274,552
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		24,678,410	22,333,814
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)		1,149,986,607	1,045,916,626
68	<b>DEFERRED DEBITS</b>			
69	Unamortized Debt Expenses (181)		39,906,558	37,700,632
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	65,060,122	68,027,230
72	Other Regulatory Assets (182.3)	232	3,297,860,533	3,058,047,442
73	Prelim. Survey and Investigation Charges (Electric) (183)		5,524,543	258,448
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	62,619,320	54,088,311
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)		13,434,928	15,368,020
82	Accumulated Deferred Income Taxes (190)	234	1,037,767,852	1,000,619,754
83	Unrecovered Purchased Gas Costs (191)		25,641,559	22,739,437
84	Total Deferred Debits (lines 69 through 83)		4,547,815,415	4,256,849,274
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		20,382,790,042	19,379,433,925

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original	(Mo, Da, Yr)	
	(2) <input type="checkbox"/> A Resubmission	04/10/2017	2016/Q4
FOOTNOTE DATA			

**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.

The balance at Dec. 31, 2016 includes \$25,549,302 for income taxes. This balance was largely driven by an overpayment for 2016 income taxes, and a reserve for the Internal Revenue Service audits, a portion of which is currently in Appeals. NSP-Minnesota expects the overpayment for 2016 will be settled in 2017 after the Xcel Energy Inc. extensions and tax returns are filed.

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

NSP-Minnesota's Prepayments (Account No. 165) balance at Dec. 31, 2015, includes \$33,756,726 for income taxes. This balance was largely driven by a reserve for the Internal Revenue Service audits, a portion of which was in Appeals, and an overpayment for 2015 income taxes. NSP-Minnesota's overpayment for 2015 was settled in 2016 after the Xcel Energy extensions and tax returns were filed.

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (mo, da, yr) 04/10/2017	Year/Period of Report end of 2016/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	3,323,810,404
7	Other Paid-In Capital (208-211)	253	2,955,813,212	0
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	1,944,055,826	1,867,056,192
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-2,809,856	-2,729,903
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)	-20,782,709	-21,081,338
16	Total Proprietary Capital (lines 2 through 15)		5,355,569,002	5,167,065,355
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	4,900,000,000	4,550,000,000
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	22,518	33,400
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		16,951,568	15,911,324
24	Total Long-Term Debt (lines 18 through 23)		4,883,070,950	4,534,122,076
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		922,463	448,244
29	Accumulated Provision for Pensions and Benefits (228.3)		332,000,000	302,990,000
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		43,538,172	62,085,623
32	Long-Term Portion of Derivative Instrument Liabilities		116,804,317	128,212,719
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		2,452,566,787	2,331,092,414
35	Total Other Noncurrent Liabilities (lines 26 through 34)		2,945,831,739	2,824,829,000
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		85,000,000	223,000,000
38	Accounts Payable (232)		411,095,526	393,075,133
39	Notes Payable to Associated Companies (233)		1,450,000	1,450,000
40	Accounts Payable to Associated Companies (234)		59,633,299	59,784,707
41	Customer Deposits (235)		110,244,496	92,148,574
42	Taxes Accrued (236)	262-263	219,084,491	203,255,169
43	Interest Accrued (237)		69,594,249	66,882,734
44	Dividends Declared (238)		89,428,150	73,497,550
45	Matured Long-Term Debt (239)		0	0

**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)		26,906,146	20,678,151
48	Miscellaneous Current and Accrued Liabilities (242)		25,487,970	31,194,364
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		133,410,192	145,310,626
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		116,804,317	128,212,719
52	Derivative Instrument Liabilities - Hedges (245)		0	112,812
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,114,530,202	1,182,177,101
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		13,042,376	11,992,608
57	Accumulated Deferred Investment Tax Credits (255)	266-267	24,175,232	25,837,882
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	331,296,972	315,499,429
60	Other Regulatory Liabilities (254)	278	1,868,456,818	1,733,392,392
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	32,924,109	34,967,609
63	Accum. Deferred Income Taxes-Other Property (282)		3,601,257,322	3,330,468,638
64	Accum. Deferred Income Taxes-Other (283)		212,635,320	219,081,835
65	Total Deferred Credits (lines 56 through 64)		6,083,788,149	5,671,240,393
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		20,382,790,042	19,379,433,925

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

**Schedule Page: 112 Line No.: 7 Column: c**

In 2016 an adjustment was recorded to move the life to date contributions of capital from FERC Account No. 207, Premium on Capital Stock, to FERC Account No. 211, Miscellaneous Paid-In Capital.

**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 column in a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
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	4,845,209,645	4,769,967,410		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,817,193,281	2,970,243,905		
5	Maintenance Expenses (402)	320-323	276,281,879	281,924,543		
6	Depreciation Expense (403)	336-337	562,969,977	521,547,012		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	30,382,102	9,781,448		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	50,715,975	46,025,861		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		3,544,366	5,777,630		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		46,895,788	23,743,966		
13	(Less) Regulatory Credits (407.4)		205,262,154	230,919,923		
14	Taxes Other Than Income Taxes (408.1)	262-263	246,436,047	230,729,787		
15	Income Taxes - Federal (409.1)	262-263	20,351,273	-34,573,036		
16	- Other (409.1)	262-263	11,230,260	-27,816,466		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	751,486,500	800,762,622		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	553,889,597	564,404,724		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,662,650	-1,729,006		
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)		3,939,977	1,727,724		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		115,649,669	108,840,618		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		4,168,382,739	4,138,206,513		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117, line 27		676,826,906	631,760,897		

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		Line No.
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)	
4,376,218,559	4,218,157,309	468,991,086	551,810,101			2
						3
2,460,909,086	2,545,922,720	356,284,195	424,321,185			4
268,989,617	273,907,874	7,292,262	8,016,669			5
521,186,468	482,470,802	41,783,509	39,076,210			6
30,122,828	9,540,543	259,274	240,905			7
46,423,974	41,720,228	4,292,001	4,305,633			8
						9
3,544,366	5,777,630					10
						11
46,895,788	21,372,852		2,371,114			12
199,269,502	229,640,386	5,992,652	1,279,537			13
225,207,847	209,109,846	21,228,200	21,619,941			14
24,558,674	-43,487,868	-4,207,401	8,914,832			15
11,489,371	-29,585,789	-259,111	1,769,323			16
693,256,554	743,711,761	58,229,946	57,050,861			17
512,418,192	510,773,401	41,471,405	53,631,323			18
-1,390,399	-1,450,702	-272,251	-278,304			19
						20
						21
3,939,977	1,727,724					22
						23
114,541,540	107,801,987	1,108,129	1,038,631			24
3,730,108,043	3,624,670,373	438,274,696	513,536,140			25
646,110,516	593,486,936	30,716,390	38,273,961			26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL		Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
			Current Year (c)	Previous Year (d)		
27	Net Utility Operating Income (Carried forward from page 114)		676,826,906	631,760,897		
28	Other Income and Deductions					
29	Other Income					
30	Nonutility Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		28,263,966	27,924,349		
34	(Less) Expenses of Nonutility Operations (417.1)		23,234,805	21,901,881		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-79,953	-102,171		
37	Interest and Dividend Income (419)		94,766	762,097		
38	Allowance for Other Funds Used During Construction (419.1)		27,731,929	26,819,016		
39	Miscellaneous Nonoperating Income (421)		-1,059,672	14,546,734		
40	Gain on Disposition of Property (421.1)			206		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		31,716,231	48,048,350		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)			60,021		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		6,651,473	1,285,857		
46	Life Insurance (426.2)		-3,206,963	-1,745,889		
47	Penalties (426.3)		192,393	39,512		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		2,312,930	2,130,628		
49	Other Deductions (426.5)		2,105,925	223,033		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		8,055,758	1,993,162		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	177,835	179,703		
53	Income Taxes-Federal (409.2)	262-263	109,423	1,174,412		
54	Income Taxes-Other (409.2)	262-263	-1,689,321	24,141,180		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	22,452,084	39,282,113		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	23,813,032	56,031,060		
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)		-2,763,011	8,746,348		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		26,423,484	37,308,840		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		215,414,227	199,692,091		
63	Amort. of Debt Disc. and Expense (428)		4,251,253	3,809,419		
64	Amortization of Loss on Reaquired Debt (428.1)		1,933,092	1,927,811		
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)		315,226	217,456		
68	Other Interest Expense (431)		5,164,288	3,395,525		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		12,571,378	12,724,862		
70	Net Interest Charges (Total of lines 62 thru 69)		214,506,708	196,317,440		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		488,743,682	472,752,297		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)			115,913,047		
75	Net Extraordinary Items (Total of line 73 less line 74)			-115,913,047		
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)			-115,913,047		
78	Net Income (Total of line 71 and 77)		488,743,682	356,839,250		

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

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

	Electric	Gas
Minnesota Renewable Development Fund	\$ 28,210,993	
Minnesota Revenue Decoupling Mechanism	1,781,212	
Minnesota Transmission Cost Recovery	11,013,382	
North Dakota Renewable Energy Rider	578,236	
Private Fuel Storage	109,819	
Sherco Unit 3 Depreciation Deferral	439,537	
South Dakota Production Tax Credit	4,548,992	
Transco Amortization	213,617	
	\$ 46,895,788	

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

	Electric	Gas
Minnesota Renewable Development Fund	\$ 17,279,149	
Minnesota Transmission Cost Recovery	1,884,453	
North Dakota Transmission Cost Recovery	1,419,327	
Minnesota Gas Utility Infrastructure		1,306,717
Minnesota State Energy Policy	213,942	1,064,397
Sherco Unit 3 Depreciation Deferral	466,162	
Private Fuel Storage	109,819	
	\$ 21,372,852	\$ 2,371,114

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

	Electric	Gas
Asset Retirement Obligation Regulatory Credits	\$ 144,664,127	\$ 1,367,645
Minnesota Gas Utility Infrastructure		3,794,505
Minnesota Renewable Energy Standard	3,236,115	
Minnesota State Energy Policy		830,502
North Dakota Transmission Cost Recovery	140,817	
South Dakota Transmission Cost Recovery	645,586	
Theoretical Depreciation Reserve Surplus	50,493,485	
South Dakota Infrastructure	89,372	
	\$ 199,269,502	\$ 5,992,652

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

	Electric	Gas
Asset Retirement Obligation Regulatory Credits	\$ 117,342,530	\$ 1,279,537
Theoretical Depreciation Reserve Surplus	75,810,719	
Department of Energy Refund Amortization	25,734,695	
Minnesota Renewable Energy Standard	8,166,398	
South Dakota Infrastructure	1,972,777	
North Dakota Renewable Energy Rider	225,175	
South Dakota Transmission Cost Recovery	388,092	
	\$ 229,640,386	\$ 1,279,537

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

Income on Company Owned Life Insurance.

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

Income on Company Owned Life Insurance.

**Schedule Page: 114 Line No.: 74 Column: d**

Account No. 435 activity is related to the March 2015 regulatory decision for the Monticello LCM/EPU project. The pre-tax components of the entry are shown below, and an

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original	(Mo, Da, Yr)	
	(2) <input type="checkbox"/> A Resubmission	04/10/2017	2016/Q4
FOOTNOTE DATA			

estimated tax benefit of \$47,290,205 on this loss is recorded in Account No. 411.1 Provision for Deferred Income Taxes-Credit. See Note 8 to the Financial Statements.

Account No. 449.1	\$ 8,011,783
Account No. 431	301,065
Account No. 435	115,913,047
	\$ 124,225,895

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		1,866,978,569	1,764,872,848
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11	Rounding		-1	
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		-1	
16	Balance Transferred from Income (Account 433 less Account 418.1)		488,823,635	356,941,421
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			-411,824,000	( 254,835,700)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-411,824,000	( 254,835,700)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,943,978,203	1,866,978,569
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

**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)		1,944,055,826	1,867,056,192
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-2,729,903	( 2,627,733)
50	Equity in Earnings for Year (Credit) (Account 418.1)		-79,953	( 102,171)
51	(Less) Dividends Received (Debit)			
52	Rounding			1
53	Balance-End of Year (Total lines 49 thru 52)		-2,809,856	( 2,729,903)

**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)	488,743,682	356,839,250
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	595,142,891	477,700,172
5	Amortization of Nuclear Fuel	116,981,547	106,424,403
6	Amortization of Premium, Discount and Debt Expense	6,184,345	5,737,230
7	Monticello LCM/EPU Loss		124,225,895
8	Deferred Income Taxes (Net)	196,235,955	219,608,951
9	Investment Tax Credit Adjustment (Net)	-1,662,650	-1,729,006
10	Net (Increase) Decrease in Receivables	-54,699,563	106,860,755
11	Net (Increase) Decrease in Inventory	-1,117,628	-53,471,390
12	Net (Increase) Decrease in Allowances Inventory	2,561	3,646
13	Net Increase (Decrease) in Payables and Accrued Expenses	54,733,176	-8,067,823
14	Net (Increase) Decrease in Other Regulatory Assets	-10,248,431	21,586,568
15	Net Increase (Decrease) in Other Regulatory Liabilities	72,092,209	-91,073,024
16	(Less) Allowance for Other Funds Used During Construction	27,731,929	26,819,016
17	(Less) Undistributed Earnings from Subsidiary Companies	-79,953	-102,171
18	Other: (Increase) Decrease in Accrued Utility Revenues	-32,488,910	24,485,626
19	Other: Net Realized and Unrealized Hedging and Derivative Transactions	3,729,421	16,074,870
20	Other: Changes in Other Current Assets and Liabilities	7,586,434	65,666,702
21	Other: Changes in Noncurrent Liabilities and Deferred Amounts	-108,478,866	-24,047,149
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,305,084,197	1,320,108,831
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-983,799,643	-1,678,904,907
27	Gross Additions to Nuclear Fuel	-124,638,474	-103,243,281
28	Gross Additions to Common Utility Plant	-96,098,451	-72,739,940
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-27,731,929	-26,819,016
31	Other: Proceeds from Insurance Recoveries		27,237,056
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,176,804,639	-1,800,832,056
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	-100,000	-140,000
40	Contributions and Advances from Assoc. and Subsidiary Companies		90,000
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43	Investments in Utility Money Pool Arrangement	-747,500,000	-385,900,000
44	Purchase of Investment Securities (a)	-7,060,431	
45	Proceeds from Sales of Investment Securities (a)		

**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	747,500,000	385,900,000
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	-1,043,265	-2,661,813
54	Other: Purchase of Investments in External Decommissioning Fund	-499,237,578	-1,257,924,231
55	Other: Proceeds from Sale of Investments in External Decommission Fnd	478,865,830	1,236,873,138
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,205,380,083	-1,824,594,962
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	342,502,577	587,545,088
62	Preferred Stock		
63	Common Stock		
64	Other: Capital Contributions by Parent	96,672,311	347,304,401
65	Other: Borrowings Under Utility Money Pool Arrangement	424,000,000	294,500,000
66	Net Increase in Short-Term Debt (c)		81,000,000
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	863,174,888	1,310,349,489
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-10,882	-250,012,534
74	Preferred Stock		
75	Common Stock		
76	Other: Repayments Under Utility Money Pool Arrangement	-424,000,000	-294,500,000
77			
78	Net Decrease in Short-Term Debt (c)	-138,000,000	
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-395,893,400	-259,140,525
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-94,729,394	506,696,430
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	4,974,720	2,210,299
87			
88	Cash and Cash Equivalents at Beginning of Period	42,482,578	40,272,279
89			
90	Cash and Cash Equivalents at End of period	47,457,298	42,482,578

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

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

<u>Changes in Noncurrent Liabilities and Deferred Amounts</u>	
Change in pension and employee benefit obligation	\$ (41,394,473)
Change in deferred debits	(16,699,226)
Change in deferred credits	(32,311,933)
Change in noncurrent liabilities	(18,073,234)
	\$ <u>(108,478,866)</u>

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

<u>Changes in Noncurrent Liabilities and Deferred Amounts</u>	
Change in pension and employee benefit obligation	\$ (25,861,043)
Change in deferred debits	67,242,841
Change in deferred credits	(33,790,123)
Change in noncurrent liabilities	(31,638,824)
	\$ <u>(24,047,149)</u>

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

Cash and Working Funds (130)	\$ 0
Cash (131)	15,842,241
Working Fund (135)	124,640
Temporary Cash Investments (136)	31,490,417
Cash and Cash Equivalents at End of Period	\$ <u>47,457,298</u>

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

Cash and Working Funds (130)	\$ 0
Cash (131)	22,170,934
Working Fund (135)	128,040
Temporary Cash Investments (136)	20,183,604
Cash and Cash Equivalents at End of Period	\$ <u>42,482,578</u>

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report 04/10/2017	Year/Period of Report End of <u>2016/Q4</u>
---	---	------------------------------	--

NOTES TO FINANCIAL STATEMENTS

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

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

## 1. Summary of Significant Accounting Policies

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

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

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

- Current maturities of long-term debt are included as long-term debt, while GAAP requires such maturities to be classified as current liabilities.
- Accumulated deferred income taxes are shown as long-term assets and liabilities at their gross amounts in the FERC presentation, in contrast to the GAAP presentation as net long-term assets and liabilities.
- Regulatory assets and liabilities are classified as current and noncurrent for GAAP presentation, while the FERC requires all regulatory assets and liabilities to be classified as noncurrent deferred debits and credits, respectively.
- Unrecognized tax benefits are recorded for temporary differences in accounts established for accumulated deferred income taxes in the FERC presentation, in contrast to the GAAP presentation as taxes accrued and noncurrent other liabilities.
- 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.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

- Certain utility plant cost disallowances are presented as an extraordinary deduction in the FERC presentation in contrast to the GAAP presentation in which they are included in operating expenses.
- Wholly-owned subsidiaries are reported using the equity method of accounting in the FERC presentation and are required to be consolidated for GAAP.
- Adjustments to theoretical excess depreciation reserves are 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.
- Deferred financing costs are included as deferred debits in the FERC presentation in contrast to the GAAP presentation in which they are included as a deduction from the carrying amount of long-term debt.

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

**(Thousands of Dollars)**

**Balance Sheet:**

Net utility plant	\$	550,940
Current assets		187,526
Current liabilities		140,698
Other long-term assets		(3,298,976)
Long-term debt and other long-term liabilities		(2,701,208)

**Statement of Income:**

Operating revenues	\$	55,077
Operating expenses		(166,571)
Other income and deductions		2,401
Interest Charges		(470)

**Statement of Cash Flows:**

Cash provided by operating activities	\$	(84)
Cash used in investing activities		100
Cash provided by financing activities		—

**Use of Estimates** — In recording transactions and balances resulting from business operations, NSP-Minnesota uses estimates based on the best information available. Estimates are used for such items as plant depreciable lives or potential disallowances, asset retirement obligations (AROs), certain regulatory assets and liabilities, tax provisions, uncollectible amounts, environmental costs, unbilled revenues, jurisdictional fuel and energy cost allocations and actuarially determined benefit costs. The recorded estimates are revised when better information becomes available or when actual amounts can be determined. Those revisions can affect operating results.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

**Regulatory Accounting** — NSP-Minnesota accounts for certain 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 (OCI), 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 OCI, 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 restructuring or other 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 financial condition, results of operations and cash flows. See Note 11 for further discussion of regulatory assets and liabilities.

**Revenue Recognition** — Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers is based on the reading of their meter, 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 presents its revenues net of any excise or other fiduciary-type 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. Revenues and charges for energy transacted through 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.

NSP-Minnesota has various rate-adjustment mechanisms in place that provide for the recovery of natural gas, electric fuel and purchased energy costs. These 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, under governing regulatory commission rate orders, 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.

Certain rate rider mechanisms qualify as alternative revenue programs under generally accepted accounting principles. 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, revenue is recognized equal to the revenue requirement, including return on rate base items, for the qualified mechanisms. The mechanisms are revised periodically for differences between the total amount collected under the riders and the revenue recognized, which may increase or decrease the level of revenue collected from customers.

**Conservation Programs** — NSP-Minnesota has implemented programs in its retail jurisdictions to assist customers in reducing peak demand and conserving energy on the electric and natural gas system. These programs include a wide variety of programs including, but not limited to, commercial process efficiency and lighting upgrades, as well as incentives for participation in air-conditioning interruption.

The costs incurred for conservation improvement programs (CIP) are deferred if it is probable future revenue will be provided to permit recovery of the incurred cost. Recorded revenues for incentive programs designed for recovery of lost margins and/or conservation performance incentives are limited to amounts expected to be collected within 24 months from the annual period in which they are earned.

NSP-Minnesota's CIP program costs are recovered through a combination of base rate revenue and rider mechanisms. The revenue

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

billed to customers recovers incurred costs for conservation programs and also incentive amounts that are designed to encourage NSP-Minnesota's achievement of energy conservation goals and to compensate for related lost sales margin. NSP-Minnesota recognizes regulatory assets to reflect the amount of costs or earned incentives that have not yet been collected from customers.

**Property, Plant and Equipment and Depreciation** — 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 major 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. Property, plant and equipment also includes costs associated with property held for future use. The depreciable lives of certain plant assets are reviewed annually and revised, if appropriate.

Property, plant and equipment is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. A loss is recognized in the current period if it becomes probable that part of a cost of a plant under construction or recently completed plant will be disallowed for recovery from customers and a reasonable estimate of the disallowance can be made. See Note 8 for a discussion of the loss recognized in 2015 related to the Monticello life cycle management (LCM)/extended power uprate (EPU) project. For investments in property, plant and equipment that are abandoned and not expected to go into service, incurred costs and related deferred tax amounts are compared to the discounted estimated future rate recovery, and a loss is recognized, if necessary.

NSP-Minnesota records depreciation expense related to its plant 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 3.2 and 2.9 percent for the years ended Dec. 31, 2016 and 2015, respectively.

**Leases** — NSP-Minnesota evaluates a variety of contracts for lease classification at inception, including purchase power agreements (PPAs) and rental arrangements for office space, vehicles, and equipment. Contracts determined to contain a lease because of per unit pricing that is other than fixed or market price, terms regarding the use of a particular asset, and other factors are evaluated further to determine if the arrangement is a capital lease. See Note 9 for further discussion of leases.

**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 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 service rates. In addition to construction-related amounts, cost of capital also is recorded to reflect returns on capital used to finance conservation programs in Minnesota.

Generally AFUDC costs are recovered from customers as the related property is depreciated. However, in some cases, including certain wind and transmission projects, the Minnesota Public Utilities Commission (MPUC) or the FERC have approved a more current recovery of the cost of capital associated with large capital projects, through various riders, resulting in a lower recognition of AFUDC.

**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 discussion of AROs.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

**Nuclear Decommissioning** — Nuclear decommissioning studies estimate NSP-Minnesota’s ultimate costs of decommissioning its nuclear power plants and are performed at least every three years and submitted to the MPUC and other state commissions for approval. NSP-Minnesota’s most recent triennial nuclear decommissioning studies were approved by the MPUC in October 2015. These studies reflect NSP-Minnesota’s plans for prompt dismantlement of the Monticello and PI facilities. These studies assume that NSP-Minnesota will store spent fuel on site pending removal to a United States government facility.

For rate making purposes, NSP-Minnesota recovers the total decommissioning costs related to its nuclear power plants over each facility’s expected service life based on the triennial decommissioning studies filed with the MPUC and other state commissions. 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. See Note 10 for further discussion of the approved nuclear decommissioning studies and funded amounts. For financial reporting purposes, NSP-Minnesota accounts for nuclear decommissioning as an ARO as described above.

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 sheets. See Note 7 for further discussion of the nuclear decommissioning fund.

**Nuclear Fuel Expense** — Nuclear fuel expense, which is recorded as NSP-Minnesota’s nuclear generating plants use fuel, includes the cost of fuel used in the current period (including AFUDC) and costs associated with the end-of-life fuel segments.

**Nuclear Refueling Outage Costs** — NSP-Minnesota uses a deferral and amortization method for nuclear refueling operating costs. This method amortizes refueling outage costs over the period between refueling outages consistent with how the costs are recovered ratably in electric rates.

**Income Taxes** — NSP-Minnesota accounts for income taxes using the asset and liability method, which requires the 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 the tax 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 income in the period that includes the enactment date.

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. In making such a determination, all available evidence is considered, including scheduled reversals of deferred tax liabilities, projected future taxable income, tax planning strategies and recent financial operations.

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, the reversal of some temporary differences are accounted for as current income tax expense. 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 ITCs related to public utility property. Utility rate regulation also has resulted in the recognition of certain regulatory assets and liabilities related to income taxes, which are summarized in Note 11.

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.

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

See Note 5 for further discussion of income taxes.

**Types of and Accounting for 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. All derivative instruments not designated and qualifying for the normal purchases and normal sales exception, as defined by the accounting guidance for derivatives and hedging, are recorded on the balance sheets at fair value as derivative instruments. This includes certain instruments used to mitigate market risk for the utility operations including transmission in organized markets and all instruments related to the commodity trading operations. The 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. The 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 costs; and interest rate hedging transactions are recorded as a component of interest expense. NSP-Minnesota is allowed to recover in electric or natural gas rates the costs of certain financial instruments purchased to reduce commodity cost volatility. For further information on derivatives entered to mitigate commodity price risk on behalf of electric and natural gas customers, see Note 7.

**Cash Flow Hedges** — Certain qualifying hedging relationships are designated as a hedge of a forecasted transaction or future cash flow (cash flow hedge). Changes in the fair value of a derivative designated as a cash flow hedge, to the extent effective are included in OCI, or deferred as a regulatory asset or liability based on recovery mechanisms until earnings are affected by the hedged transaction.

**Normal Purchases and Normal Sales** — NSP-Minnesota enters into contracts for the purchase and sale of commodities for use in its business operations. Derivatives and hedging accounting guidance requires a company to evaluate these contracts to determine whether the contracts are derivatives. Certain contracts that meet the definition of a derivative may be exempted from derivative accounting if designated as normal purchases or normal sales.

NSP-Minnesota evaluates all of its contracts at inception to determine if they are derivatives and if they meet the normal purchases and normal sales designation requirements. None of the contracts entered into within the commodity trading operations qualify for a normal purchases and normal sales designation.

See Note 7 for further discussion of NSP-Minnesota's risk management and derivative activities.

**Commodity Trading Operations** — Pursuant to the joint operating agreement (JOA) approved by the FERC, some of NSP-Minnesota's commodity trading margins are apportioned to Public Service Company of Colorado (PSCo) and Southwestern Public Service Company (SPS). Commodity trading activities are not associated with energy produced from NSP-Minnesota's generation assets or energy and capacity purchased to serve native load. Commodity trading contracts are recorded at fair market value and commodity trading results include the impact of all margin-sharing mechanisms. For further information, see Note 7.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

**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 NAVs. For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used as a primary input 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 for an identical contract in an active market, NSP-Minnesota may use quoted prices for similar contracts or internally prepared valuation models to determine fair value. For the 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. For further information, see Note 7.

**Cash and Cash Equivalents** — NSP-Minnesota considers investments in certain instruments, including commercial paper and money market funds, 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** — All inventory is recorded at average cost.

**Renewable Energy Credits (RECs)** — RECs are marketable environmental instruments that represent proof that energy was generated from eligible renewable energy sources. RECs are awarded upon delivery of the associated energy and can be bought and sold. RECs are typically used as a form of measurement of compliance to renewable portfolio standards (RPS) enacted by those states that are encouraging construction and consumption from renewable energy sources, but can also be sold separately from the energy produced. NSP-Minnesota acquires RECs from the generation or purchase of renewable power.

When RECs are purchased or acquired in the course of generation they are recorded as inventory at cost in Account 158.1. The cost of RECs that are utilized for compliance purposes is recorded as electric fuel and purchased power expense.

Sales of RECs that are purchased or acquired in the course of generation are recorded in electric utility operating revenues on a gross basis. The cost of these RECs, related transaction costs, and amounts credited to customers under margin-sharing mechanisms are recorded in electric fuel and purchased power expense.

**Emission Allowances** — Emission allowances, including the annual sulfur dioxide (SO<sub>2</sub>) and nitrogen oxide (NO<sub>x</sub>) emission allowance entitlement received from the United States Environmental Protection Agency (EPA), are recorded at cost plus associated broker commission fees. NSP-Minnesota follows the inventory accounting model for all emission allowances. Sales of emission allowances are included in electric utility operating revenues and the operating activities section of the statements of cash flows.

**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, excluding inflationary increases, are recorded based on experience, an assessment of the current situation and the technology currently available for use in the remediation. The recorded costs are regularly adjusted as estimates are revised and remediation proceeds. If other participating potentially responsible parties (PRPs) exist and acknowledge their potential involvement with a site, costs are estimated and recorded only for NSP-Minnesota's expected share of the cost. Any future costs of restoring sites where operation may be extended are treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses, which may include final remediation costs.

See Note 9 for further discussion of environmental costs.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

**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 under applicable accounting guidance requires management to make various assumptions and estimates.

Based on regulatory recovery mechanisms, certain unrecognized actuarial gains and losses and unrecognized prior service costs or credits are recorded as regulatory assets and liabilities, rather than OCI.

See Note 6 for further discussion of benefit plans and other postretirement benefits.

**Guarantees** — NSP-Minnesota recognizes, upon issuance or modification of a guarantee, a liability for the fair market value of the obligation that has been assumed in issuing the guarantee. This liability includes consideration of specific triggering events and other conditions which may modify the ongoing obligation to perform under the guarantee.

The obligation recognized is reduced over the term of the guarantee as NSP-Minnesota is released from risk under the guarantee. See Note 9 for specific details of issued guarantees.

**Subsequent Events** — Management has evaluated the impact of events occurring after Dec. 31, 2016 up to Feb. 24, 2017, the date NSP-Minnesota's GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 10, 2017. These 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:

<u>Name</u>	<u>Geographic Area</u>	<u>Economic Interest</u>
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.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

**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:

(Thousands of Dollars)	2016	2015
Current assets	\$ 1,607	\$ 1,730
Other assets	1,192	1,118
<b>Total assets</b>	<b>\$ 2,799</b>	<b>\$ 2,848</b>
Current liabilities	\$ 213	\$ 277
Other liabilities	13	18
Equity	2,573	2,553
<b>Total liabilities and equity</b>	<b>\$ 2,799</b>	<b>\$ 2,848</b>

(Thousands of Dollars)	2016	2015
Operating revenues	\$ 45	\$ 32
Operating loss	(145)	(172)
<b>Net Loss</b>	<b>(80)</b>	<b>(102)</b>

**3. Borrowings and Other Financing Instruments**

**Short-Term Borrowings**

**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:

(Amounts in Millions, Except Interest Rates)	Twelve Months Ended Dec. 31, 2016	Twelve Months Ended Dec. 31, 2015
Borrowing limit	\$ 250	\$ 250
Amount outstanding at period end	—	—
Average amount outstanding	16	5
Maximum amount outstanding	225	69
Weighted average interest rate, computed on a daily basis	0.69 %	0.53 %
Weighted average interest rate at period end	N/A	N/A

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

**Commercial Paper** — NSP-Minnesota meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility. Commercial paper outstanding for NSP-Minnesota was as follows:

(Amounts in Millions, Except Interest Rates)	Twelve Months Ended Dec. 31, 2016	Twelve Months Ended Dec. 31, 2015
Borrowing limit	\$ 500	\$ 500
Amount outstanding at period end	85	223
Average amount outstanding	73	96
Maximum amount outstanding	353	327
Weighted average interest rate, computed on a daily basis	0.65 %	0.43 %
Weighted average interest rate at end of period	0.94	0.72

**Letters of Credit** — NSP-Minnesota uses letters of credit, generally with terms of one-year, to provide financial guarantees for certain operating obligations. At Dec. 31, 2016 and 2015, there were \$11 million and \$18 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 2016, NSP-Minnesota entered into an amended five-year credit agreement with a syndicate of banks. The total borrowing limit under the amended credit agreement remained at \$500 million. The amended credit agreement has substantially the same terms and conditions as the prior credit agreement with the following exceptions:

- The maturity extended from October 2019 to June 2021.
- The Eurodollar borrowing margin on this line of credit was reduced to a range of 75 to 150 basis points per year, from a range of 87.5 to 175 basis points per year, based upon applicable long-term credit ratings.
- The commitment fees, calculated on the unused portion of the line of credit, were reduced to a range of 6 to 22.5 basis points per year, from a range of 7.5 to 27.5 basis points per year, also based on applicable long-term credit ratings.

NSP-Minnesota has the right to request an extension of the termination date for two additional one-year periods. The extension requests are subject to majority bank group approval.

Other features of NSP-Minnesota's credit facility include:

- NSP-Minnesota may increase its credit facility by up to \$100 million.
- The credit facility has a financial covenant requiring that the debt-to-total capitalization ratio be less than or equal to 65 percent. NSP-Minnesota was in compliance as its debt-to-total capitalization ratio was 48 percent at both Dec. 31, 2016 and 2015. 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.
- The credit facility has a cross-default provision that provides NSP-Minnesota will be in default on its borrowings under the facility if NSP-Minnesota or any of its subsidiaries whose total assets exceed 15 percent of NSP-Minnesota's consolidated total assets, default on certain indebtedness in an aggregate principal amount exceeding \$75 million.
- NSP-Minnesota was in compliance with all financial covenants on its debt agreements as of Dec. 31, 2016 and 2015.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

At Dec. 31, 2016, NSP-Minnesota had the following committed credit facility available (in millions):

Credit Facility (a)	Drawn (b)	Available
\$ 500	\$ 96	\$ 404

(a) This credit facility matures in June 2021.

(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 credit facility outstanding at Dec. 31, 2016 and 2015.

### ***Long-Term Borrowings and Other Financing Instruments***

Generally, all real and personal 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 associated with refinanced debt are deferred and amortized over the life of the related new issuance, in accordance with regulatory guidelines.

In 2016, NSP-Minnesota issued \$350 million of 3.6 percent first mortgage bonds due May 15, 2046. In 2015, NSP-Minnesota issued \$300 million of 2.2 percent first mortgage bonds due Aug. 15, 2020 and \$300 million of 4.0 percent first mortgage bonds due Aug. 15, 2045.

During the next five years, NSP-Minnesota has long-term debt maturities of \$500 million and \$300 million due in 2018 and 2020, respectively.

***Deferred Financing Costs*** — Deferred financing costs of approximately \$39.9 million and \$37.7 million, net of amortization, are presented as deferred debits at Dec. 31, 2016 and 2015, respectively. NSP-Minnesota is amortizing these financing costs over the remaining maturity periods of the related debt.

***Dividend and Other Capital-Restrictions*** — NSP-Minnesota's dividends are subject to the FERC's jurisdiction, which prohibits the payment of dividends out of capital accounts; payment of dividends is allowed out of retained earnings only.

NSP-Minnesota's first mortgage indenture places certain restrictions on the amount of cash dividends it can pay to Xcel Energy Inc., the holder of its common stock. Even with this restriction, NSP-Minnesota could have paid more than \$1.7 billion in additional cash dividends on common stock at both Dec. 31, 2016 and 2015.

The most restrictive dividend limitation for NSP-Minnesota is imposed by its state regulatory commissions. NSP-Minnesota's state regulatory commissions indirectly limit the amount of dividends NSP-Minnesota can pay to Xcel Energy Inc. by requiring an equity-to-total capitalization ratio between 46.9 percent and 57.3 percent. NSP-Minnesota's equity-to-total capitalization ratio was 52.1 percent at Dec. 31, 2016 and \$1.0 billion in retained earnings was not restricted. Total capitalization for NSP-Minnesota was \$10.3 billion at Dec. 31, 2016, which did not exceed the limits imposed by the commissions of \$10.75 billion.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

#### 4. Joint Ownership of Generation and Transmission Facilities

Following are the investments by NSP-Minnesota in jointly owned generation and transmission facilities and the related ownership percentages as of Dec. 31, 2016:

(Thousands of Dollars)	Plant in Service	Accumulated Depreciation <sup>(a)</sup>	CWIP	Ownership %
Electric Generation:				
Sherco Unit 3	\$ 589,903	\$ 398,367	\$ 9,714	59%
Sherco Common Facilities Units 1, 2 and 3	145,447	95,909	540	80
Sherco Substation	4,790	3,146	—	59
Electric Transmission:				
Grand Meadow Line and Substation	10,647	1,871	—	50
CapX2020	965,289	116,942	56,024	51
Total	\$ 1,716,076	\$ 616,235	\$ 66,278	

(a) Asset retirement obligation is not included.

NSP-Minnesota has approximately 517 megawatts (MW) of jointly owned generating capacity. NSP-Minnesota's share of operating expenses and construction expenditures are included in the applicable utility accounts. Each of the respective owners is responsible for providing its own financing.

#### 5. Income Taxes

**Consolidated Appropriations Act, 2016** — In December 2015, the Consolidated Appropriations Act, 2016 (Act) was signed into law. The Act provides for the following:

- Immediate expensing, or “bonus depreciation,” of 50 percent for property placed in service in 2015, 2016, and 2017; 40 percent for property placed in service in 2018; and 30 percent for property placed in service in 2019. Additionally, some longer production period property placed in service in 2020 will be eligible for bonus depreciation;
- Production tax credits (PTCs) at 100 percent of the credit rate (\$0.023 per kilowatt hours (KWh)) for wind energy projects that begin construction by the end of 2016; 80 percent of the credit rate for projects that begin construction in 2017; 60 percent of the credit rate for projects that begin construction in 2018; and 40 percent of the credit rate for projects that begin construction in 2019. The wind energy PTC was not extended for projects that begin construction after 2019;
- Investment tax credits (ITCs) at 30 percent for commercial solar projects that begin construction by the end of 2019; 26 percent for projects that begin construction in 2020; 22 percent for projects that begin construction in 2021; and 10 percent for projects thereafter;
- Research and experimentation (R&E) credit was permanently extended; and
- Delay of two years (until 2020) of the excise tax on certain employer-provided health insurance plans.

The accounting related to the Act was recorded beginning in the fourth quarter of 2015 because a change in tax law is accounted for beginning in the period of enactment.

**Federal Tax Loss Carryback Claims** — In 2012-2015, NSP-Minnesota identified certain expenses related to 2009, 2010, 2011, 2013, 2014 and 2015 that qualify for an extended carryback beyond the typical two-year carryback period. As a result of a higher tax rate in prior years, NSP-Minnesota recognized a tax benefit of approximately \$5 million in 2015, \$17 million in 2014, \$12 million in 2013 and \$15 million in 2012.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

**Federal Audit** — NSP-Minnesota is a member of the Xcel Energy affiliated group that files a consolidated federal income tax return. In 2012, the Internal Revenue Service (IRS) commenced an examination of tax years 2010 and 2011, including the 2009 carryback claim. As of Dec. 31, 2016, the IRS had proposed an adjustment to the federal tax loss carryback claims that would result in \$14 million of income tax expense for the 2009 through 2011 claims, and the 2013 through 2015 claims. In the fourth quarter of 2015, the IRS forwarded the issue to the Office of Appeals (Appeals). In 2016 the IRS audit team and Xcel Energy presented their cases to Appeals; however, the outcome and timing of a resolution is uncertain. The statute of limitations applicable to Xcel Energy's 2009 through 2011 federal income tax returns, following extensions, expires in December 2017. Xcel Energy has recognized its best estimate of income tax expense that will result from a final resolution of the IRS's proposed adjustment of the carryback claims.

In the third quarter of 2015, the IRS commenced an examination of tax years 2012 and 2013. As of Dec. 31, 2016, the IRS had not proposed any material adjustments to tax years 2012 and 2013. Subsequent to year-end, the IRS proposed an adjustment to tax years 2012 through 2013 that may impact Xcel Energy's NOL and tax credit carryforwards and ETR. However, Xcel Energy is continuing to evaluate the IRS' proposal and the outcome and timing of a resolution is uncertain.

**State Audits** — NSP-Minnesota is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of Dec. 31, 2016, NSP-Minnesota's earliest open tax year that is subject to examination by state taxing authorities under applicable statutes of limitations is 2009. In June 2016, the state of Minnesota began an audit of years 2010 through 2014. As of Dec. 31, 2016, Minnesota had not proposed any adjustments, and there were no other state income tax audits in progress.

**Unrecognized Tax Benefits** — The unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the annual effective tax rate (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 of cash to the taxing authority to an earlier period.

**Uncertainty in Income Taxes** — The FERC has not fully adopted the accounting 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.

A reconciliation of the amount of unrecognized tax benefit is as follows:

(Millions of Dollars)	Dec. 31, 2016	Dec. 31, 2015
Unrecognized tax benefit — Permanent tax positions	\$ 21.5	\$ 20.1
Unrecognized tax benefit — Temporary tax positions	39.3	35.3
Total unrecognized tax benefit	<u>\$ 60.8</u>	<u>\$ 55.4</u>

A reconciliation of the beginning and ending amount of unrecognized tax benefit is as follows:

(Millions of Dollars)	2016	2015
Balance at Jan. 1	\$ 55.4	\$ 30.4
Additions based on tax positions related to the current year	3.7	14.0
Reductions based on tax positions related to the current year	(0.2)	(2.1)
Additions for tax positions of prior years	3.9	14.0
Reductions for tax positions of prior years	(2.0)	(0.9)
Settlements with taxing authorities	—	—
Balance at Dec. 31	<u>\$ 60.8</u>	<u>\$ 55.4</u>

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

The unrecognized tax benefit amounts were reduced by the tax benefits associated with net operating losses (NOLs) and tax credit carryforwards. The amounts of tax benefits associated with NOL and tax credit carryforwards are as follows:

(Millions of Dollars)	Dec. 31, 2016	Dec. 31, 2015
NOL and tax credit carryforwards	\$ (19.3)	\$ (15.2)

It is reasonably possible that NSP-Minnesota's amount of unrecognized tax benefits could significantly change in the next 12 months as the IRS Appeals and audit progress, the Minnesota audit progresses, and other state audits resume. As the IRS Appeals and IRS and Minnesota audits progress, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately \$32 million.

The payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards. A reconciliation of the beginning and ending amount of the payable for interest related to unrecognized tax benefits are as follows:

(Millions of Dollars)	Dec. 31, 2016	Dec. 31, 2015
Payable for interest related to unrecognized tax benefits at Jan. 1	\$ (0.2)	\$ (0.1)
Interest (expense) income related to unrecognized tax benefits	(1.8)	(0.1)
Payable for interest related to unrecognized tax benefits at Dec. 31	\$ (2.0)	\$ (0.2)

No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2016 and 2015.

**Other Income Tax Matters** — NOL amounts represent the amount of 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)	2016	2015
Federal NOL carryforward	\$ 940	\$ 1,055
Federal tax credit carryforwards	232	171
State NOL carryforwards	265	277
State tax credit carryforwards, net of federal detriment	68	32
Valuation allowances for state credit carryforwards, net of federal detriment	(60)	(25)

The federal carryforward periods expire between 2021 and 2036. The state carryforward periods expire between 2017 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. The following reconciles such differences for the years ending Dec. 31:

	2016	2015
Federal statutory rate	35.0%	35.0%
Increases (decreases) in tax from:		
Tax credits recognized, net of federal income tax expense	(9.0)	(6.3)
State income taxes, net of federal income tax benefit	5.8	5.9
Regulatory differences — utility plant items	(0.3)	(1.7)
Net operating loss carryback	—	(0.9)
Other, net	—	1.6
Effective income tax rate	31.5%	33.6%

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

The components of income tax expense for the years ending Dec. 31 were:

(Thousands of Dollars)	2016	2015
Current federal tax expense (benefit)	\$ 19,338	\$ (41,023)
Current state tax expense (benefit)	9,308	(3,926)
Current change in unrecognized tax expense	1,356	7,875
Deferred federal tax expense	142,328	167,532
Deferred state tax expense	53,908	52,077
Deferred investment tax credits	(1,663)	(1,729)
Total income tax expense	<u>\$ 224,575</u>	<u>\$ 180,806</u>

The components of deferred income tax expense for the years ending Dec. 31 were:

(Thousands of Dollars)	2016	2015
Deferred tax expense excluding items below	\$ 225,151	\$ 218,035
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(28,692)	1,401
Tax (expense) benefit allocated to other comprehensive income and other	(223)	173
Deferred tax expense	<u>\$ 196,236</u>	<u>\$ 219,609</u>

The components of the net deferred tax liability at Dec. 31 were as follows:

(Thousands of Dollars)	2016	2015
Deferred tax liabilities:		
Differences between book and tax bases of property	\$ 3,604,910	\$ 3,330,774
Regulatory assets	154,805	156,499
Employee benefits	64,233	76,043
Other	22,869	21,202
Total deferred tax liabilities	<u>\$ 3,846,817</u>	<u>\$ 3,584,518</u>
Deferred tax assets:		
Difference between book and tax bases of property	\$ 304,635	\$ 295,335
NOL carryforward	350,115	391,447
Tax credit carryforward	239,610	177,851
Employee benefits	57,220	59,411
Rate refund	21,094	26,298
Regulatory liabilities	9,188	10,188
Deferred investment tax credits	10,663	11,419
Other	45,243	28,671
Total deferred tax assets	<u>\$ 1,037,768</u>	<u>\$ 1,000,620</u>
Net deferred tax liability	<u>\$ 2,809,049</u>	<u>\$ 2,583,898</u>

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

## 6. Benefit Plans and Other Postretirement Benefits

Consistent with the process for rate recovery of pension and postretirement benefits for its employees, NSP-Minnesota accounts for its participation in, and related costs of, pension and other postretirement benefit plans sponsored by Xcel Energy Inc. as multiple employer plans. NSP-Minnesota is responsible for its share of cash contributions, plan costs and obligations and is entitled to its share of plan assets; accordingly, NSP-Minnesota accounts for its pro rata share of these plans, including pension expense and contributions, resulting in accounting consistent with that of a single employer plan exclusively for NSP-Minnesota employees.

Xcel Energy, which includes NSP-Minnesota, offers various benefit plans to its employees. Approximately 62 percent of employees that receive benefits are represented by several local labor unions under several collective-bargaining agreements. At Dec. 31, 2016, NSP-Minnesota had 1,959 bargaining employees covered under a collective-bargaining agreement, which expires at the end of 2019. NSP-Minnesota also had an additional 253 nuclear operation bargaining employees covered under several collective-bargaining agreements. These agreements expire in 2017, 2018 and 2019.

The plans invest in various instruments which are disclosed under the accounting guidance for fair value measurements which establishes a hierarchical framework for disclosing the observability of the inputs utilized in measuring fair value. The three levels in the hierarchy and examples of each level are as follows:

Level 1 — Quoted prices are available in active markets for identical assets as of the reporting date. The types of assets 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 included in Level 2 are typically either comparable to actively traded securities or contracts, or priced with models using highly observable inputs.

Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets included in Level 3 are those with inputs requiring significant management judgment or estimation.

Specific valuation methods include the following:

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

*Insurance contracts* — Insurance contract fair values take into consideration the value of the investments in separate accounts of the insurer, which are priced based on observable inputs.

*Investments in commingled funds, 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, which take into consideration the value of underlying fund investments, as well as the other accrued assets and liabilities of a fund, in order to determine a per share market value. The investments in commingled funds may be redeemed for NAV with proper notice. Proper notice varies by fund and can range from daily with a few days' notice to annually with 90 days' notice. Private equity 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. Depending on the fund, unscheduled distributions from real estate investments may require approval of the fund or may be redeemed with proper notice, which is typically quarterly with 45-90 days' notice; however, withdrawals from real estate investments 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.

*Derivative Instruments* — Fair values for foreign currency derivatives are determined using pricing models based on the prevailing forward exchange rate of the underlying currencies. The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

## Pension 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, the employee's average pay and, in some cases, social security benefits. Xcel Energy Inc.'s and NSP-Minnesota's policy is to fully fund into an external trust the actuarially determined pension costs recognized for ratemaking and financial reporting purposes, 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 unfunded, nonqualified benefits for compensation that is in excess of the limits applicable to the qualified pension plans, with distributions attributable to NSP-Minnesota's funded by NSP-Minnesota's operating cash flows. The total obligations of the SERP and nonqualified plan as of Dec. 31, 2016 and 2015 were \$43.5 million and \$41.8 million, respectively, of which \$5.8 million and \$5.1 million were attributable to NSP-Minnesota. In 2016 and 2015, Xcel Energy recognized net benefit cost for financial reporting for the SERP and nonqualified plans of \$7.9 million and \$9.5 million, respectively, of which \$0.6 million was attributable to NSP-Minnesota in both years.

In 2016, Xcel Energy established rabbi trusts to provide partial funding for future distributions of the SERP and its deferred compensation plan. Rabbi trust funding of deferred compensation plan distributions attributable to NSP-Minnesota will be supplemented by NSP-Minnesota's operating cash flows as determined necessary. For more information regarding the funding of rabbi trusts, see Note 7 to the financial statements. Also in 2016, Xcel Energy amended the deferred compensation plan to provide eligible participants the ability to diversify deferred settlements of equity awards, other than time-based equity awards, into various fund options.

Xcel Energy Inc. and NSP-Minnesota base the investment-return assumption on expected long-term performance for each of the investment types included in the pension asset portfolio and consider the historical returns achieved by the asset portfolio over the past 20-year or longer period, as well as the long-term return levels projected and recommended by investment experts. Xcel Energy Inc. and NSP-Minnesota continually review pension assumptions. The pension cost determination assumes a forecasted mix of investment types over the long term.

- Investment returns in 2016 were below the assumed level of 7.10 percent;
- Investment returns in 2015 were below the assumed level of 7.25 percent; and
- In 2017, NSP-Minnesota's expected investment-return assumption is 7.10 percent.

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

The following table presents the target pension asset allocations for NSP-Minnesota at Dec. 31 for the upcoming year:

	2016	2015
Domestic and international equity securities	40%	41%
Long-duration fixed income and interest rate swap securities	23	23
Short-to-intermediate fixed income securities	16	14
Alternative investments	19	20
Cash	2	2
Total	100%	100%

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

The 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. The aggregate projected asset allocation presented in the table above for the master pension trust results from the plan-specific strategies.

### Pension Plan Assets

The following tables present, for each of the fair value hierarchy levels, NSP-Minnesota's pension plan assets that are measured at fair value as of Dec. 31, 2016 and 2015:

The following tables present, for each of the fair value hierarchy levels, NSP-Minnesota's pension plan assets that are measured at fair value as of Dec. 31, 2016 and 2015:

(Thousands of Dollars)	Dec. 31, 2016				
	Level 1	Level 2	Level 3	Investments Measured at NAV	Total
Cash equivalents	\$ 25,929	\$ —	\$ —	\$ —	\$ 25,929
Commingled funds:					
U.S. equity funds	—	—	—	140,973	140,973
Non U.S. equity funds	—	—	—	107,618	107,618
U.S. corporate bond funds	—	—	—	69,652	69,652
Emerging market equity funds	—	—	—	56,460	56,460
Emerging market debt funds	—	—	—	48,091	48,091
Commodity funds	—	—	—	5,854	5,854
Private equity investments	—	—	—	30,621	30,621
Real estate	—	—	—	53,373	53,373
Other commingled funds	—	—	—	57,611	57,611
Debt securities:					
Government securities	—	84,082	—	—	84,082
U.S. corporate bonds	—	62,091	—	—	62,091
Non U.S. corporate bonds	—	9,966	—	—	9,966
Mortgage-backed securities	—	1,674	—	—	1,674
Asset-backed securities	—	793	—	—	793
Equity securities:					
U.S. equities	27,775	—	—	—	27,775
Other	—	633	—	—	633
<b>Total</b>	<b>\$ 53,704</b>	<b>\$ 159,239</b>	<b>\$ —</b>	<b>\$ 570,253</b>	<b>\$ 783,196</b>

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

(Thousands of Dollars)	Dec. 31, 2015					Total
	Level 1	Level 2	Level 3	Investments Measured at NAV		
Cash equivalents	\$ 40,273	\$ —	\$ —	\$ —	\$ 40,273	
Derivatives	—	596	—	—	596	
Commingled funds:						
U.S. equity funds	—	—	—	116,289	116,289	
Non U.S. equity funds	—	—	—	112,075	112,075	
U.S. corporate bond funds	—	—	—	67,078	67,078	
Emerging market equity funds	—	—	—	50,239	50,239	
Emerging market debt funds	—	—	—	48,593	48,593	
Commodity funds	—	—	—	16,507	16,507	
Private equity investments	—	—	—	40,023	40,023	
Real estate	—	—	—	58,100	58,100	
Other commingled funds	—	—	—	62,516	62,516	
Debt securities:						
Government securities	—	87,510	—	—	87,510	
U.S. corporate bonds	—	60,417	—	—	60,417	
Non U.S. corporate bonds	—	9,697	—	—	9,697	
Asset-backed securities	—	680	—	—	680	
Equity securities:						
U.S. equities	28,257	—	—	—	28,257	
Other	—	1,393	—	—	1,393	
<b>Total</b>	<b>\$ 68,530</b>	<b>\$ 160,293</b>	<b>\$ —</b>	<b>\$ 571,420</b>	<b>\$ 800,243</b>	

There were no assets transferred in or out of Level 3 for the years ended Dec. 31, 2016 and 2015.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

**Benefit Obligations** — A comparison of the actuarially computed pension benefit obligation and plan assets for NSP-Minnesota is presented in the following table:

(Thousands of Dollars)	2016	2015
<b>Accumulated Benefit Obligation at Dec. 31</b>	\$ 971,544	\$ 954,610
<b>Change in Projected Benefit Obligation:</b>		
Obligation at Jan. 1	\$ 1,023,123	\$ 1,099,671
Service cost	28,307	31,556
Interest cost	45,431	43,214
Plan amendments	1,411	—
Actuarial loss (gain)	46,992	(60,091)
Benefit payments	(108,756)	(91,227)
Obligation at Dec. 31	\$ 1,036,508	\$ 1,023,123

(Thousands of Dollars)	2016	2015
<b>Change in Fair Value of Plan Assets:</b>		
Fair value of plan assets at Jan. 1	\$ 800,243	\$ 880,915
Actual return (loss) on plan assets	42,279	(22,180)
Employer contributions	49,430	32,735
Benefit payments	(108,756)	(91,227)
Fair value of plan assets at Dec. 31	\$ 783,196	\$ 800,243

(Thousands of Dollars)	2016	2015
<b>Funded Status of Plans at Dec. 31:</b>		
Funded status (a)	\$ (253,312)	\$ (222,880)

(a) Amounts are recognized in other noncurrent liabilities on NSP-Minnesota's balance sheet.

(Thousands of Dollars)	2016	2015
<b>Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:</b>		
Net loss	\$ 618,675	\$ 589,796
Prior service cost	5,185	4,710
Total	\$ 623,860	\$ 594,506

(Thousands of Dollars)	2016	2015
<b>Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:</b>		
Other regulatory assets	\$ 623,860	\$ 594,506
Measurement date	Dec. 31, 2016	Dec. 31, 2015

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

	2016	2015
<b>Significant Assumptions Used to Measure Benefit Obligations:</b>		
Discount rate for year-end valuation	4.13%	4.66%
Expected average long-term increase in compensation level	3.75%	4.00%
Mortality table	RP-2014	RP-2014

**Mortality** — In 2014, the Society of Actuaries published a new mortality table (RP-2014) and projection scale (MP-2014) that increased the overall life expectancy of males and females. On Dec. 31, 2014 NSP-Minnesota adopted the RP-2014 table, with modifications, based on its population and specific experience and a modified MP-2014 projection scale. During 2016, a new projection table was released (MP-2016). In 2016, NSP-Minnesota adopted a modified version of the MP-2016 table and will continue to utilize the RP-2014 base table, modified for company experience.

**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 2015 through 2017 to meet minimum funding requirements.

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

- \$150.0 million in January 2017, of which \$59.4 million was attributable to NSP-Minnesota;
- \$125.2 million in 2016, of which \$49.4 million was attributable to NSP-Minnesota; and
- \$90.1 million in 2015, of which \$32.7 million was attributable to NSP-Minnesota.

For future years, Xcel Energy and NSP-Minnesota anticipate contributions will be made as necessary.

**Plan Amendments** — The 2016 increase in the projected benefit obligation resulted from a change in the discount rate basis for lump sum conversion to annuity participants and annuity conversion to lump sum participants in the Xcel Energy Pension Plan. In 2015, there were no plan amendments made which affected the projected benefit obligation.

**Benefit Costs** — The components of NSP-Minnesota's net periodic pension cost were:

(Thousands of Dollars)	2016	2015
Service cost	\$ 28,307	\$ 31,556
Interest cost	45,431	43,214
Expected return on plan assets	(60,944)	(62,830)
Amortization of prior service cost	936	936
Amortization of net loss	36,777	46,192
Net periodic pension cost	50,507	59,068
Costs not recognized due to effects of regulation	(20,865)	(30,766)
Net benefit cost recognized for financial reporting	\$ 29,642	\$ 28,302
	2016	2015

<b>Significant Assumptions Used to Measure Costs:</b>		
Discount rate	4.66%	4.11%
Expected average long-term increase in compensation level	4.00	3.75
Expected average long-term rate of return on assets	7.10	7.25

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

In addition to the benefit costs in the table above, for the pension plans sponsored by Xcel Energy, Inc., costs are allocated to NSP-Minnesota based on Xcel Energy Services Inc. employees' labor costs. Amounts allocated to NSP-Minnesota were \$10.9 million and \$11.0 million in 2016 and 2015, respectively. Pension costs include an expected return impact for the current year that may differ from actual investment performance in the plan. The return assumption used for 2017 pension cost calculations is 7.10 percent. The cost calculation uses a market-related valuation of pension assets. Xcel Energy, including NSP-Minnesota, uses a calculated value method to determine the market-related value of the plan assets. The market-related value begins with the fair market value of assets as of the beginning of the year. The market-related value is determined by adjusting the fair market value of assets to reflect the investment gains and losses (the difference between the actual investment return and the expected investment return on the market-related value) during each of the previous five years at the rate of 20 percent per year. As these differences between actual investment returns and the expected investment returns are incorporated into the market-related value, the differences are recognized over the expected average remaining years of service for active employees.

### Defined Contribution Plans

Xcel Energy, which includes NSP-Minnesota, maintains 401(k) and other defined contribution plans that cover substantially all employees. The expense to these plans for NSP-Minnesota was approximately \$11.8 million in 2016 and \$11.2 million in 2015.

### Postretirement Health Care Benefits

Xcel Energy, which includes NSP-Minnesota, has a contributory health and welfare benefit plan that provides health care and death benefits to certain Xcel Energy retirees. NSP-Minnesota discontinued contributing toward health care benefits for nonbargaining employees retiring after 1998 and for bargaining employees who retired after 1999.

Regulatory agencies for nearly all retail and wholesale utility customers have allowed rate recovery of accrued postretirement benefit costs.

**Plan Assets** — Certain state agencies that regulate Xcel Energy Inc.'s utility subsidiaries also have issued guidelines related to the funding of postretirement benefit costs. These assets are invested in a manner consistent with the investment strategy for the pension plan.

The following table presents the target postretirement asset allocations for Xcel Energy Inc. and NSP-Minnesota at Dec. 31 for the upcoming year:

	2016	2015
Domestic and international equity securities	25%	25%
Short-to-intermediate fixed income securities	57	57
Alternative investments	13	13
Cash	5	5
Total	100%	100%

Xcel Energy Inc. and NSP-Minnesota base investment-return assumptions for the postretirement health care fund assets on expected long-term performance for each of the investment types included in the asset portfolio. Assumptions and target allocations are determined at the master trust level. The investment mix at each of Xcel Energy Inc.'s utility subsidiaries may vary from the investment mix of the total asset portfolio. The assets are invested in a portfolio according to Xcel Energy Inc.'s and NSP-Minnesota's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize the necessity of contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the projected allocation of assets to selected asset classes, given the long-term risk, return, correlation and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any particular industry, index, or entity. Market volatility is not considered to be a material factor in postretirement health care costs.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

The following tables present, for each of the fair value hierarchy levels, NSP-Minnesota's proportionate allocation of the total postretirement benefit plan assets that are measured at fair value as of Dec. 31, 2016 and 2015:

(Thousands of Dollars)	Dec. 31, 2016				
	Level 1	Level 2	Level 3	Investments Measured at NAV	Total
Cash equivalents	\$ 172	\$ —	\$ —	\$ —	\$ 172
Insurance contracts	—	395	—	—	395
Commingled funds:					
U.S. equity funds	—	—	—	455	455
U.S. fixed income funds	—	—	—	227	227
Emerging market debt funds	—	—	—	254	254
Other commingled funds	—	—	—	459	459
Debt securities:					
Government securities	—	315	—	—	315
U.S. corporate bonds	—	521	—	—	521
Non U.S. corporate bonds	—	144	—	—	144
Asset-backed securities	—	158	—	—	158
Mortgage-backed securities	—	240	—	—	240
Equity securities:					
Non U.S. equities	342	—	—	—	342
Other	—	12	—	—	12
<b>Total</b>	<b>\$ 514</b>	<b>\$ 1,785</b>	<b>\$ —</b>	<b>\$ 1,395</b>	<b>\$ 3,694</b>

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

(Thousands of Dollars)	Dec. 31, 2015				
	Level 1	Level 2	Level 3	Investments Measured at NAV	Total
Cash equivalents	\$ 130	\$ —	\$ —	\$ —	\$ 130
Insurance contracts	—	313	—	—	313
Commingled funds:					
U.S. equity funds	—	—	—	253	253
Non U.S. equity funds	—	—	—	223	223
U.S. fixed income funds	—	—	—	161	161
Emerging market equity funds	—	—	—	74	74
Emerging market debt funds	—	—	—	237	237
Other commingled funds	—	—	—	410	410
Debt securities:					
Government securities	—	260	—	—	260
U.S. corporate bonds	—	397	—	—	397
Non U.S. corporate bonds	—	86	—	—	86
Asset-backed securities	—	190	—	—	190
Mortgage-backed securities	—	236	—	—	236
Other	—	(1)	—	—	(1)
<b>Total</b>	<b>\$ 130</b>	<b>\$ 1,481</b>	<b>\$ —</b>	<b>\$ 1,358</b>	<b>\$ 2,969</b>

There were no assets transferred in or out of Level 3 for the years ended Dec. 31, 2016 and 2015.

**Benefit Obligations** — A comparison of the actuarially computed benefit obligation and plan assets for NSP-Minnesota is presented in the following table:

(Thousands of Dollars)	2016	2015
<b>Change in Projected Benefit Obligation:</b>		
Obligation at Jan. 1	\$ 88,684	\$ 97,946
Service cost	123	159
Interest cost	3,925	3,814
Medicare subsidy reimbursements	29	59
Plan participants' contributions	451	552
Actuarial loss (gain)	1,880	(5,197)
Benefit payments	(8,397)	(8,649)
Obligation at Dec. 31	<b>\$ 86,695</b>	<b>\$ 88,684</b>

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

(Thousands of Dollars)	2016	2015
<b>Change in Fair Value of Plan Assets:</b>		
Fair value of plan assets at Jan. 1	\$ 2,969	\$ 2,081
Actual return on plan assets	7	8
Plan participants' contributions	451	552
Employer contributions	8,664	8,977
Benefit payments	(8,397)	(8,649)
Fair value of plan assets at Dec. 31	\$ 3,694	\$ 2,969

(Thousands of Dollars)	2016	2015
<b>Funded Status of Plans at Dec. 31:</b>		
Funded status	\$ (83,001)	\$ (85,715)
Other noncurrent liabilities	(83,001)	(85,715)
Net postretirement amounts recognized on balance sheets	\$ (83,001)	\$ (85,715)

(Thousands of Dollars)	2016	2015
<b>Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:</b>		
Net loss	\$ 41,306	\$ 40,864
Prior service credit	(18,433)	(21,469)
Total	\$ 22,873	\$ 19,395

(Thousands of Dollars)	2016	2015
<b>Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:</b>		
Other regulatory assets	\$ 21,386	\$ 18,133
Deferred income taxes	606	515
Net-of-tax accumulated OCI	881	747
Total	\$ 22,873	\$ 19,395

Measurement date	Dec. 31, 2016	Dec. 31, 2015
------------------	---------------	---------------

(Thousands of Dollars)	2016	2015
<b>Significant Assumptions Used to Measure Benefit Obligations:</b>		
Discount rate for year-end valuation	4.13%	4.65%
Mortality table	RP 2014	RP 2014
Health care costs trend rate — initial	5.50%	6.00%

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Effective Jan. 1, 2017, the initial medical trend rate was decreased from 6.0 percent to 5.5 percent. The ultimate trend assumption remained at 4.5 percent. The period until the ultimate rate is reached is two years. Xcel Energy Inc. and NSP-Minnesota base the medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost increases experienced by the retiree medical plan.

A one-percent change in the assumed health care cost trend rate would have the following effects on NSP-Minnesota:

(Thousands of Dollars)	One Percentage Point	
	Increase	Decrease
Accumulated postretirement benefit obligation	\$ 8,241	\$ (7,020)
Service and interest components	426	(360)

**Cash Flows** — The postretirement health care plans have no funding requirements under income tax and other retirement-related regulations other than fulfilling benefit payment obligations, when claims are presented and approved under the plans. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities. Xcel Energy, which includes NSP-Minnesota, contributed \$17.9 million and \$18.3 million during 2016 and 2015, respectively, of which \$8.7 million and \$9.0 million were attributable to NSP-Minnesota. Xcel Energy expects to contribute approximately \$11.8 million during 2017, of which \$8.0 million is attributable to NSP-Minnesota.

**Plan Amendments** — In 2016 and 2015, there were no plan amendments made which affected the benefit obligation.

**Benefit Costs** — The components of NSP-Minnesota's net periodic postretirement benefit costs were:

(Thousands of Dollars)	2016	2015
Service cost	\$ 123	\$ 159
Interest cost	3,925	3,814
Expected return on plan assets	(172)	(121)
Amortization of prior service credit	(3,036)	(3,036)
Amortization of net loss	1,603	2,092
Net periodic postretirement benefit cost	\$ 2,443	\$ 2,908
	<u>2016</u>	<u>2015</u>

**Significant Assumptions Used to Measure Costs:**

Discount rate	4.65 %	4.08 %
Expected average long-term rate of return on assets	5.80	5.80

In addition to the benefit costs in the table above, for the postretirement health care plans sponsored by Xcel Energy, Inc., costs are allocated to NSP-Minnesota based on Xcel Energy Services Inc. employees' labor costs.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

## Projected Benefit Payments

The following table lists NSP-Minnesota's projected benefit payments for the pension and postretirement benefit plans:

(Thousands 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
2017	\$ 92,146	\$ 8,014	\$ 7	\$ 8,007
2018	88,080	7,763	7	7,756
2019	90,293	7,403	7	7,396
2020	89,938	7,185	8	7,177
2021	88,160	6,799	6	6,793
2022-2026	396,573	29,092	39	29,053

## 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, including electrical workers, boilermakers, and other construction and facilities workers who may perform services for more than one employer during a given period 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.

Contributions to multiemployer plans were as follows for the years ended Dec. 31, 2016 and 2015. The average number of NSP-Minnesota union employees covered by the multiemployer pension plans decreased to approximately 700 in 2016 from approximately 850 in 2015. There were no other significant changes to the nature or magnitude of the participation of NSP-Minnesota in multiemployer plans for the years presented:

(Thousands of Dollars)	2016	2015
Multiemployer plan contributions:		
Pension	13,843	17,223
Other postretirement benefits	86	135
Total	13,929	17,358

## 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 certain 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. The three levels in the hierarchy are as follows:

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.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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 the following:

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

*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, which take into consideration the value of underlying fund investments, as well as the other accrued assets and liabilities of a fund, in order to determine a per-share market value. The investments in commingled funds may be redeemed for NAV with proper notice. Proper notice varies by fund and can range from daily with one or two days notice to annually with 90 days notice. Private equity 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 investments may be redeemed with proper notice, which is typically quarterly with 45-90 days notice; however, withdrawals from real estate investments 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. When contractual settlements extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable forecasts of long-term 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), purchased from MISO. FTRs purchased from a regional transmission organization (RTO) are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path. The value of an FTR is derived from, and designed to offset, the cost of energy congestion, which is caused by overall transmission load and other transmission constraints. 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. NSP-Minnesota's valuation process for FTRs utilizes complex iterative modeling to predict the impacts of forecasted changes in these drivers of transmission system congestion on the historical pricing of FTR purchases.

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 management's forecasts for several of the inputs to this complex valuation model – 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 to the complex model used for valuation of FTRs are insignificant to the financial statements of NSP-Minnesota.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

### Non-Derivative Instruments Fair Value Measurements

The Nuclear Regulatory Commission (NRC) requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Together with all accumulated earnings or losses, the assets of the nuclear decommissioning fund are legally restricted for the purpose of decommissioning the Monticello and PI nuclear generating plants. The fund contains cash equivalents, debt securities, equity securities and other investments – all classified as available-for-sale. NSP-Minnesota plans to reinvest matured securities until decommissioning begins. 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 of its nuclear generating plants over the lives of the plants, assuming rate recovery of all costs. Given the purpose and legal restrictions on the use of nuclear decommissioning fund assets, 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, including any other-than-temporary impairments, are deferred as a component of the regulatory asset for nuclear decommissioning.

Unrealized gains for the nuclear decommissioning fund were \$378.6 million and \$328.8 million at Dec. 31, 2016 and 2015, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were \$46.9 million and \$100.2 million at Dec. 31, 2016 and 2015, respectively.

The following tables present the cost and fair value of NSP-Minnesota's non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund at Dec. 31, 2016 and 2015:

(Thousands of Dollars)	Dec. 31, 2016					
	Cost	Fair Value			Investments Measured at NAV	Total
		Level 1	Level 2	Level 3		
<b>Nuclear decommissioning fund</b>						
Cash equivalents	\$ 20,379	\$ 20,379	\$ —	\$ —	\$ —	\$ 20,379
Commingled funds:						
Non U.S. equities	260,877	—	—	—	245,359	245,359
Emerging market debt funds	93,597	—	—	—	97,543	97,543
Commodity funds	106,571	—	—	—	92,091	92,091
Private equity investments	132,190	—	—	—	190,462	190,462
Real estate	128,630	—	—	—	187,647	187,647
Other commingled funds	151,048	—	—	—	159,489	159,489
Debt securities:						
Government securities	32,764	—	31,965	—	—	31,965
U.S. corporate bonds	104,913	—	105,772	—	—	105,772
Non U.S. corporate bonds	21,751	—	21,672	—	—	21,672
Municipal bonds	13,609	—	13,786	—	—	13,786
Mortgage-backed securities	2,785	—	2,816	—	—	2,816
Equity securities:						
U.S. equities	270,779	473,400	—	—	—	473,400
Non U.S. equities	189,100	218,381	—	—	—	218,381
<b>Total</b>	<b>\$ 1,528,993</b>	<b>\$ 712,160</b>	<b>\$ 176,011</b>	<b>\$ —</b>	<b>\$ 972,591</b>	<b>\$ 1,860,762</b>

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

(Thousands of Dollars)	Dec. 31, 2015					
	Cost	Fair Value			Investments Measured at NAV	Total
		Level 1	Level 2	Level 3		
<b>Nuclear decommissioning fund</b>						
Cash equivalents	\$ 27,484	\$ 27,484	\$ —	\$ —	\$ —	\$ 27,484
Commingled funds:						
Non U.S. equities	259,114	—	—	—	231,122	231,122
Emerging market debt funds	88,987	—	—	—	88,467	88,467
Commodity funds	99,771	—	—	—	77,338	77,338
Private equity investments	105,965	—	—	—	157,528	157,528
Real estate	115,019	—	—	—	165,190	165,190
Other commingled funds	150,877	—	—	—	164,389	164,389
Debt securities:						
Government securities	24,444	—	21,356	—	—	21,356
U.S. corporate bonds	73,061	—	65,276	—	—	65,276
Non U.S. corporate bonds	13,726	—	12,801	—	—	12,801
Municipal bonds	49,255	—	51,589	—	—	51,589
Asset-backed securities	2,837	—	2,830	—	—	2,830
Mortgage-backed securities	11,444	—	11,621	—	—	11,621
Equity securities:						
U.S. equities	273,106	432,495	—	—	—	432,495
Non U.S. equities	200,509	214,664	—	—	—	214,664
<b>Total</b>	<b>\$ 1,495,599</b>	<b>\$ 674,643</b>	<b>\$ 165,473</b>	<b>\$ —</b>	<b>\$ 884,034</b>	<b>\$ 1,724,150</b>

For the year ended Dec. 31, 2016 and 2015 there were no Level 3 nuclear decommissioning fund investments and no transfers of amounts between levels.

The following table summarizes the final contractual maturity dates of the debt securities in the nuclear decommissioning fund, by asset class, at Dec. 31, 2016:

(Thousands of Dollars)	Final Contractual Maturity				Total
	Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years	
Government securities	\$ —	\$ 9,158	\$ 149	\$ 22,658	\$ 31,965
U.S. corporate bonds	608	28,375	67,475	9,314	105,772
Non U.S. corporate bonds	—	6,477	10,525	4,670	21,672
Municipal bonds	—	205	5,763	7,818	13,786
Mortgage-backed securities	—	—	—	2,816	2,816
Debt securities	\$ 608	\$ 44,215	\$ 83,912	\$ 47,276	\$ 176,011

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

### ***Rabbi Trusts***

In June 2016, NSP-Minnesota established a rabbi trust to provide partial funding for future deferred compensation plan distributions. The following table presents the cost and fair value of the assets held in rabbi trust at Dec. 31, 2016:

(Thousands of Dollars)	December 31, 2016				
	Cost	Fair Value			Total
		Level 1	Level 2	Level 3	
<b>Rabbi Trusts (a)</b>					
Cash equivalents	\$ 7,459	\$ 7,459	\$ —	\$ —	\$ 7,459
Mutual funds	1,663	1,901	—	—	1,901
<b>Total</b>	<b>\$ 9,122</b>	<b>\$ 9,360</b>	<b>\$ —</b>	<b>\$ —</b>	<b>\$ 9,360</b>

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

Rabbi trust assets at Dec. 31, 2015 were comprised only of an immaterial amount of mutual funds.

### ***Derivative Instruments Fair Value Measurements***

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

***Interest Rate Derivatives*** — NSP-Minnesota enters into 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.

At Dec. 31, 2016, 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, including forecasted amounts for unsettled hedges, as applicable.

***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's risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee, which is made up of management personnel not directly involved in the 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.

NSP-Minnesota enters into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers but are not designated as qualifying hedging transactions. Changes in the fair value of non-trading commodity derivative instruments are recorded in OCI or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. NSP-Minnesota recorded immaterial amounts to income related to the ineffectiveness of cash flow hedges for the years ended Dec. 31, 2016 and 2015.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Additionally, 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 revenue, net of amounts credited to customers under margin-sharing mechanisms.

The following table details the gross notional amounts of commodity forwards, options and FTRs at Dec. 31:

(Amounts in Thousands) (a)(b)	2016	2015
Megawatt hours (MWh) of electricity	37,805	43,611
Million British thermal units (MMBtu) of natural gas	79,520	7,971
Gallons of vehicle fuel	—	77

(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 the 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. Given this assessment, as well as an assessment of the impact of NSP-Minnesota's own credit risk when determining the fair value of derivative liabilities, the impact of considering 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. At Dec. 31, 2016, five of NSP-Minnesota's 10 most significant counterparties for these activities, comprising \$20.2 million or 29 percent of this credit exposure, had investment grade credit ratings from Standard & Poor's Rating Services, Moody's Investor Services or Fitch Ratings. Four of the 10 most significant counterparties, comprising \$15.7 million or 23 percent of this credit exposure at Dec. 31, 2016, were not rated by these external agencies, but based on NSP-Minnesota's internal analysis, had credit quality consistent with investment grade. Another of these significant counterparties, comprising \$0.6 million or 1 percent of this credit exposure, had credit quality less than investment grade, based on ratings from internal analysis. Nine of these significant counterparties are municipal or cooperative electric entities, or other utilities.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

**Financial Impact of Qualifying Cash Flow Hedges** — The 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, is detailed in the following table:

(Thousands of Dollars)	2016	2015
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	\$ (19,090)	\$ (19,909)
After-tax net unrealized gains (losses) related to derivatives accounted for as hedges	5	(39)
After-tax net realized losses on derivative transactions reclassified into earnings	877	858
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	<u>\$ (18,208)</u>	<u>\$ (19,090)</u>

The following tables detail the impact of derivative activity during the years ended Dec. 31, 2016, 2015 and 2014 on accumulated other comprehensive loss, regulatory assets and liabilities, and income:

(Thousands of Dollars)	Year Ended Dec. 31, 2016				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income
	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
<b>Derivatives designated as cash flow hedges</b>					
Interest rate	\$ —	\$ —	\$ 1,392 <sup>(a)</sup>	\$ —	\$ —
Vehicle fuel and other commodity	8	—	104 <sup>(b)</sup>	—	—
<b>Total</b>	<u>\$ 8</u>	<u>\$ —</u>	<u>\$ 1,496</u>	<u>\$ —</u>	<u>\$ —</u>
<b>Other derivative instruments</b>					
Commodity trading	\$ —	\$ —	\$ —	\$ —	\$ 2,825 <sup>(c)</sup>
Electric commodity	—	14,459	—	(6,090) <sup>(d)</sup>	—
Natural gas commodity	—	(1,235)	—	4,031 <sup>(e)</sup>	(2,166) <sup>(e)</sup>
<b>Total</b>	<u>\$ —</u>	<u>\$ 13,224</u>	<u>\$ —</u>	<u>\$ (2,059)</u>	<u>\$ 659</u>

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

(Thousands of Dollars)	Year Ended Dec. 31, 2015				
	Pre-Tax Fair Value Losses Recognized During the Period in		Pre-Tax Losses Reclassified into Income During the Period from		Pre-Tax Losses Recognized During the Period in Income
	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
<b>Derivatives designated as cash flow hedges</b>					
Interest rate	\$ —	\$ —	\$ 1,385 <sup>(a)</sup>	\$ —	\$ —
Vehicle fuel and other commodity	(66)	—	73 <sup>(b)</sup>	—	—
<b>Total</b>	<b>\$ (66)</b>	<b>\$ —</b>	<b>\$ 1,458</b>	<b>\$ —</b>	<b>\$ —</b>
<b>Other derivative instruments</b>					
Commodity trading	\$ —	\$ —	\$ —	\$ —	\$ (7,650) <sup>(c)</sup>
Electric commodity	—	(15,483)	—	14,735 <sup>(d)</sup>	—
Natural gas commodity	—	(4,878)	—	4,762 <sup>(e)</sup>	(3,585) <sup>(e)</sup>
<b>Total</b>	<b>\$ —</b>	<b>\$ (20,361)</b>	<b>\$ —</b>	<b>\$ 19,497</b>	<b>\$ (11,235)</b>

(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 or liabilities, as appropriate.

NSP-Minnesota had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2016 and 2015. Therefore, no gains or losses from fair value hedges or related hedged transactions were recognized for these periods.

**Credit Related Contingent Features** — Contract provisions for derivative instruments that NSP-Minnesota enters into, including those recorded to the balance sheet at fair value, as well as those accounted for as normal purchase-normal sale contracts and therefore not reflected on the balance sheet, may require the posting of collateral or settlement of the contracts for various reasons, including if NSP-Minnesota is unable to maintain its credit ratings. At Dec. 31, 2016 and 2015, there were no derivative instruments in a liability position with underlying contract provisions that required the posting of collateral or settlement of outstanding contracts if the credit ratings of NSP-Minnesota were downgraded below investment grade.

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, 2016 and 2015.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

**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, 2016:

(T thousands of Dollars)	Fair Value			Fair Value Total	Counterparty Netting <sup>(b)</sup>	Total
	Level 1	Level 2	Level 3			
<b>Dec. 31, 2016</b>						
<b>Current derivative assets</b>						
Other derivative instruments:						
Commodity trading	\$ 12,053	\$ 8,651	\$ —	\$ 20,704	\$ (15,500)	\$ 5,204
Electric commodity	—	—	15,997	15,997	(677)	15,320
Natural gas commodity	—	912	—	912	—	912
Total current derivative assets	\$ 12,053	\$ 9,563	\$ 15,997	\$ 37,613	\$ (16,177)	21,436
PPAs <sup>(a)</sup>						592
Current derivative instruments						\$ 22,028
<b>Noncurrent derivative assets</b>						
Other derivative instruments:						
Commodity trading	\$ 100	\$ 31,029	\$ —	\$ 31,129	\$ (7,323)	\$ 23,806
Total noncurrent derivative assets	\$ 100	\$ 31,029	\$ —	\$ 31,129	\$ (7,323)	23,806
PPAs <sup>(a)</sup>						872
Noncurrent derivative instruments						\$ 24,678
<b>Current derivative liabilities</b>						
Other derivative instruments:						
Commodity trading	\$ 12,397	\$ 5,964	\$ —	\$ 18,361	\$ (15,837)	\$ 2,524
Electric commodity	—	—	677	677	(677)	—
Total current derivative liabilities	\$ 12,397	\$ 5,964	\$ 677	\$ 19,038	\$ (16,514)	2,524
PPAs <sup>(a)</sup>						14,082
Current derivative instruments						\$ 16,606
<b>Noncurrent derivative liabilities</b>						
Other derivative instruments:						
Commodity trading	\$ 89	\$ 23,424	\$ —	\$ 23,513	\$ (10,727)	\$ 12,786
Total noncurrent derivative liabilities	\$ 89	\$ 23,424	\$ —	\$ 23,513	\$ (10,727)	12,786
PPAs <sup>(a)</sup>						104,018
Noncurrent derivative instruments						\$ 116,804

- (a) In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting, NSP-Minnesota began recording several long-term PPAs at fair value due to accounting requirements related to underlying price adjustments. As these purchases are recovered through normal regulatory recovery mechanisms in the respective jurisdictions, the changes in fair value for these contracts were offset by regulatory assets and liabilities. During 2006, NSP-Minnesota 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.
- (b) 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, 2016. At Dec. 31, 2016, derivative assets and liabilities include no obligations to return cash collateral and rights to reclaim cash collateral of \$3.7 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreement

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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, 2015:

(T thousands of Dollars)	Fair Value			Fair Value Total	Counterparty Netting <sup>(a)</sup>	Total
	Level 1	Level 2	Level 3			
<b>Dec. 31, 2015</b>						
<b>Current derivative assets</b>						
Other derivative instruments:						
Commodity trading	\$ 88	\$ 10,269	\$ 1,250	\$ 11,607	\$ (5,542)	\$ 6,065
Electric commodity	—	—	12,441	12,441	(167)	12,274
Natural gas commodity	—	128	—	128	(6)	122
Total current derivative assets	\$ 88	\$ 10,397	\$ 13,691	\$ 24,176	\$ (5,715)	18,461
PPAs <sup>(a)</sup>						480
Current derivative instruments						\$ 18,941
<b>Noncurrent derivative assets</b>						
Other derivative instruments:						
Commodity trading	\$ —	\$ 27,399	\$ —	\$ 27,399	\$ (6,555)	\$ 20,844
Total noncurrent derivative assets	\$ —	\$ 27,399	\$ —	\$ 27,399	\$ (6,555)	20,844
PPAs <sup>(a)</sup>						1,490
Noncurrent derivative instruments						\$ 22,334
<b>Current derivative liabilities</b>						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	\$ —	\$ 113	\$ —	\$ 113	\$ —	\$ 113
Other derivative instruments:						
Commodity trading	118	7,541	554	8,213	(6,580)	1,633
Electric commodity	—	—	167	167	(167)	—
Natural gas commodity	—	1,362	—	1,362	(6)	1,356
Total current derivative liabilities	\$ 118	\$ 9,016	\$ 721	\$ 9,855	\$ (6,753)	3,102
PPAs <sup>(a)</sup>						14,109
Current derivative instruments						\$ 17,211
<b>Noncurrent derivative liabilities</b>						
Other derivative instruments:						
Commodity trading	\$ —	\$ 19,865	\$ —	\$ 19,865	\$ (9,780)	\$ 10,085
Total noncurrent derivative liabilities	\$ —	\$ 19,865	\$ —	\$ 19,865	\$ (9,780)	10,085
PPAs <sup>(a)</sup>						118,128
Noncurrent derivative instruments						\$ 128,213

(a) In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting, NSP-Minnesota began recording several long-term PPAs at fair value due to accounting requirements related to underlying price adjustments. As these purchases are recovered through normal regulatory recovery mechanisms in the respective jurisdictions, the changes in fair value for these contracts were offset by regulatory assets and liabilities. During 2006, NSP-Minnesota 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.

(b) 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, 2015. At Dec. 31, 2015, derivative assets and liabilities include no obligations to return cash collateral and rights to reclaim cash collateral of \$4.3 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

The following table presents the changes in Level 3 commodity derivatives for the years ended Dec. 31, 2016 and 2015:

(Thousands of Dollars)	Year Ended Dec. 31	
	2016	2015
Balance at Jan. 1	\$ 12,970	\$ 40,271
Purchases	27,976	40,288
Settlements	(47,192)	(38,050)
Transfers out of Level 3	—	—
Net transactions recorded during the period:		
(Losses) gains recognized in earnings <sup>(a)</sup>	(2)	1,533
Gains (losses) recognized as regulatory assets and liabilities	21,568	(31,072)
Balance at Dec. 31	\$ 15,320	\$ 12,970

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

#### ***Fair Value of Long-Term Debt***

As of Dec. 31, 2016 and 2015, other financial instruments for which the carrying amount did not equal fair value were as follows:

(Thousands of Dollars)	2016		2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	\$ 4,883,071	\$ 5,310,925	\$ 4,534,122	\$ 4,917,080

The 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. The fair value estimates are based on information available to management as of Dec. 31, 2016 and 2015, and given the observability of the inputs to these estimates, the fair values presented for long-term debt have been assigned a Level 2.

## **8. Rate Matters**

### ***Pending and Recently Concluded Regulatory Proceedings — MPUC***

***Minnesota 2016 Multi-Year Electric Rate Case*** — In November 2015, NSP-Minnesota filed a three-year electric rate case with the MPUC. The rate case is based on a requested return on equity (ROE) of 10.0 percent and a 52.50 percent equity ratio. In December 2015, the MPUC approved interim rates for 2016. The request is detailed in the table below:

Request (Millions of Dollars)	2016		2017		2018	
Rate request	\$	194.6	\$	52.1	\$	50.4
Increase percentage		6.4%		1.7%		1.7%
Interim request	\$	163.7	\$	44.9		N/A
Rate base	\$	7,800	\$	7,700	\$	7,700

### **Settlement Agreement**

In August 2016, NSP-Minnesota and various parties reached a settlement which resolves all revenue requirement issues in dispute. The settlement agreement requires the approval of the MPUC.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Key terms of the settlement are listed below:

- Four-year period covering 2016-2019;
- Annual sales true-up as detailed below:
  - 2016 weather-normalized actuals used to set final 2016 rates, no cap;
  - 2016-2019 full decoupling for residential and non-demand metered commercial classes with a 3 percent cap; and
  - 2017-2019 annual true-up for non-decoupled classes with a 3 percent cap.
- ROE of 9.2 percent and an equity ratio of 52.5 percent;
- Nuclear related costs will not be considered provisional;
- Continued use of all existing riders, however no new riders may be utilized during the four-year term;
- Deferral of incremental 2016 property tax expense above a fixed threshold to 2018 and 2019;
- Four-year stay out provision for rate cases;
- Property tax true-up mechanism for 2017-2019; and
- Capital expenditure true-up mechanism for 2016-2019.

(Millions of Dollars, incremental)	2016	2017	2018	2019	Total
Settlement revenues (a)	\$ 74.99	\$ 59.86	\$ —	\$ 50.12	\$ 184.97
NSP-Minnesota's sales true-up (b)	59.95	—	—	(0.20)	59.75
Total rate impact (c)	\$ 134.94	\$ 59.86	\$ —	\$ 49.92	\$ 244.72

(a) The settlement revenues are based on the Department of Commerce's sales forecast.

(b) Sales actual data and related revenue calculations were filed with the MPUC on Feb. 6, 2017.

(c) The total rate impact reflects an increase of 4.62 percent in 2016; 2.05 percent in 2017; 0 percent in 2018 and 1.71 percent in 2019.

A current liability that is consistent with the settlement and represents NSP-Minnesota's best estimate of a refund obligation for 2016 associated with interim rates was recorded as of Dec. 31, 2016.

On March 1, 2017, the Administrative Law Judge (ALJ) issued his recommendation in the NSP-Minnesota rate case. The ALJ recommended that the MPUC approve the settlement as it will contribute to establishing just and reasonable rates and that no objections to the settlement are sufficient to merit rejection. The ALJ also provided recommendations for a majority of the revenue requirement issues in dispute in the event the MPUC decides to reject the settlement.

The MPUC decision is anticipated in June 2017.

**Monticello Prudence Investigation** — In 2013, NSP-Minnesota completed the Monticello LCM/EPU project. The multi-year project extended the life of the facility and increased the capacity from 600 to 671 MW in 2015. The Monticello LCM/EPU project expenditures were approximately \$665 million. Total capitalized costs were approximately \$748 million, which includes AFUDC. In 2008, project expenditures were initially estimated at approximately \$320 million, excluding AFUDC.

In 2013, the MPUC initiated an investigation to determine whether the final costs for the Monticello LCM/EPU project were prudent. In March 2015, the MPUC voted to allow for full recovery, including a return, on \$415 million of the total plant costs (inclusive of AFUDC), but only allow recovery of the remaining \$333 million of costs with no return on this portion of the investment over the remaining life of the plant. As a result of these determinations, Xcel Energy recorded an estimated pre-tax loss of \$129 million in the first quarter of 2015, after which the remaining book value of the Monticello project represented the present value of the estimated future cash flows.

**2016 Transmission Cost Recovery Adjustment (TCR) Filing** — In January 2017, the MPUC issued an order approving NSP-Minnesota's requested 2016 revenue requirements of \$78.4 million to recover costs for three CapX2020 projects and two additional projects.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

### Electric, Purchased Gas and Resource Adjustment Clauses

**CIP and CIP Rider** — CIP expenses are recovered through base rates and a rider that is adjusted annually. The estimated average annual electric and natural gas incentives for 2016 are \$30.6 million and \$3.6 million, respectively, based on the approved savings goals. The MPUC approved the following for NSP-Minnesota:

- A new CIP financial incentive mechanism for the 2017-2019 triennial period with an average forecasted incentive of \$12.5 million for electric conservation and \$1.8 million for gas conservation;
- The 2015 CIP electric and natural gas financial incentives totaling \$43.3 million and \$5.8 million, respectively; and
- This proposed 2016 electric and natural gas CIP riders with estimated 2016 recovers of \$45.1 million of electric CIP expenses and \$15.4 million of natural gas CIP expenses. This proposed recovery through the riders is in addition to an estimated \$90.2 million and \$3.8 million through electric and gas base rates, respectively.

**Gas Utility Infrastructure Cost (GUIC) Rider** — In 2016, NSP-Minnesota filed the GUIC rider with the MPUC for approval to recover the cost of natural gas infrastructure investments in Minnesota to improve safety and reliability. Costs include funding for pipeline assessments as well as deferred costs from NSP-Minnesota's existing sewer separation and pipeline integrity management programs. NSP-Minnesota requested recovery of approximately \$22.1 million from Minnesota gas utility customers beginning April 1, 2017. An MPUC decision is expected in the first half of 2017.

**Annual Automatic Adjustment (AAA) of Charges** — In 2016, the Department of Commerce (DOC) recommended the MPUC should hold utilities responsible for incremental costs of replacement power incurred due to unplanned outages at nuclear facilities under certain circumstances. The DOC's recommendation could impact replacement power cost recovery for the PI nuclear facility outages allocated to the Minnesota jurisdiction during the AAA fiscal year ended June 30, 2015. NSP-Minnesota expects a MPUC decision in mid-2017.

### Pending Regulatory Proceedings — FERC

**MISO ROE Complaints/ROE Adder** — In November 2013, a group of customers filed a complaint at the FERC against MISO transmission owners (TOs), including NSP-Minnesota and NSP-Wisconsin. The complaint argued for a reduction in the ROE in transmission formula rates in the MISO region from 12.38 percent to 9.15 percent, a prohibition on capital structures in excess of 50 percent equity, and the removal of ROE adders (including those for RTO membership and for being an independent transmission company), effective Nov. 12, 2013.

In December 2015, an ALJ initial decision recommended the FERC approve a ROE of 10.32 percent, which the FERC upheld in an order issued on Sept. 28, 2016. This ROE is applicable for the 15 month refund period from Nov. 12, 2013 to Feb. 11, 2015, and prospectively from the date of the FERC order. The total prospective ROE is 10.82 percent, which includes a previously approved 50 basis point adder for RTO membership.

In February 2015, a second complaint seeking to reduce the MISO region ROE from 12.38 percent to 8.67 percent prior to any adder was filed, which the FERC set for hearings, resulting in a second period of potential refund from Feb. 12, 2015 to May 11, 2016. The MPUC, North Dakota Public Service Commission (NDPSC), South Dakota Public Utility Commission and the DOC joined a joint complainant/intervenor initial brief recommending an ROE of approximately 8.81 percent. FERC staff recommended a ROE of 8.78 percent. The MISO TOs recommended a ROE of 10.92 percent. On June 30, 2016, the ALJ recommended a ROE of 9.7 percent, the midpoint of the upper half of the discounted cash flow range. A FERC decision is expected later in 2017.

As of Dec. 31, 2016, NSP-Minnesota has recognized a current liability for the Nov. 12, 2013 to Feb. 11, 2015 complaint period based on the 10.32 percent ROE provided in the FERC order, as well as a current liability representing the best estimate of the final ROE for the second complaint period.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

## 9. Commitments and Contingencies

### Commitments

**Capital Commitments** — NSP-Minnesota has made commitments in connection with a portion of its projected capital expenditures. NSP-Minnesota's capital commitments primarily relate to wind project plans:

**Upper Midwest Wind Projects** — NSP-Minnesota has issued a request for proposal (RFP), seeking up to 1,500 MW of wind energy projects. The RFP requests both PPAs and build-own-transfer proposals. NSP-Minnesota has submitted a request to self-build 750 MW of this total.

**Fuel Contracts** — NSP-Minnesota has entered into various long-term commitments for the purchase and delivery of a significant portion of its current coal, nuclear fuel and natural gas requirements. These contracts expire in various years between 2017 and 2033. NSP-Minnesota is required to pay additional amounts depending on actual quantities shipped under these agreements.

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas storage and transportation
2017	\$ 264.3	\$ 113.2	\$ 74.4	\$ 98.1
2018	226.3	60.8	1.4	93.3
2019	33.4	111.1	1.4	85.1
2020	—	37.7	1.4	74.3
2021	—	90.2	1.4	73.8
Thereafter	—	449.5	0.7	404.8
<b>Total <sup>(a)</sup></b>	<b>\$ 524.0</b>	<b>\$ 862.5</b>	<b>\$ 80.7</b>	<b>\$ 829.4</b>

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

Additional expenditures for fuel and natural gas storage and transportation will be required to meet expected future electric generation and natural gas needs. NSP-Minnesota's risk of loss, in the form of increased costs from market price changes in fuel, is mitigated through the use of natural gas and energy cost-rate adjustment mechanisms, which provide for pass-through of most fuel, storage and transportation costs to customers.

**PPAs** — NSP-Minnesota has entered into PPAs with other utilities and energy suppliers with expiration dates through 2039 for purchased power to meet system load and energy requirements and meet operating reserve obligations. In general, these agreements provide for energy payments, based on actual energy delivered and capacity payments. Certain PPAs accounted for as executory contracts also contain minimum energy purchase commitments. Capacity and energy payments are typically contingent on the independent power producing entity meeting certain contract obligations, including plant availability requirements. Certain contractual payments are adjusted based on market indices. The effects of price adjustments on our financial results are mitigated through purchased energy cost recovery mechanisms.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Included in electric fuel and purchased power expenses for PPAs, accounted for as executory contracts, were payments for capacity of \$89.8 million and \$104.4 million in 2016 and 2015, respectively. At Dec. 31, 2016, the estimated future payments for capacity and energy that NSP-Minnesota is obligated to purchase pursuant to these executory contracts, subject to availability, are as follows:

(Millions of Dollars)	Capacity	Energy (a)
2017	\$ 83.6	\$ 87.3
2018	53.1	93.2
2019	54.2	98.7
2020	54.8	105.4
2021	64.5	139.8
Thereafter	254.0	522.8
<b>Total (b)</b>	<b>\$ 564.2</b>	<b>\$ 1,047.2</b>

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

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

Additional energy payments under these PPAs and PPAs accounted for as operating leases will be required to meet expected future electric demand.

**Leases** — NSP-Minnesota leases a variety of equipment and facilities used in the normal course of business. These leases, primarily for office space, railcars, generating facilities, natural gas pipeline transportation, vehicles, aircraft and power-operated equipment, are accounted for as operating leases. Total expenses under operating lease obligations were approximately \$79.1 million and \$78.9 million for 2016 and 2015, respectively. These expenses include capacity payments for PPAs accounted for as operating leases of \$63.5 million and \$61.5 million in 2016 and 2015, respectively, recorded to electric fuel and purchased power expenses.

Included in the future commitments under operating leases are estimated future capacity payments under PPAs that have been accounted for as operating leases in accordance with the applicable accounting guidance. Future commitments under all operating leases are:

(Millions of Dollars)	Operating Leases	PPA (a) (b) Operating Leases	Total Operating Leases
2017	\$ 8.0	\$ 64.5	\$ 72.5
2018	8.1	65.5	73.6
2019	12.6	82.4	95.0
2020	7.5	95.1	102.6
2021	7.4	96.5	103.9
Thereafter	51.4	842.1	893.5

(a) Amounts do not include PPAs accounted for as executory contracts.

(b) PPA operating leases contractually expire through 2039.

**Guarantees** — Under NSP-Minnesota's railcar lease agreement, accounted for as an operating lease, NSP-Minnesota guarantees the lessor proceeds from sale of the leased assets at the end of the lease term will at least equal the guaranteed residual value. The guarantee issued by NSP-Minnesota limits its exposure to a maximum amount stated in the guarantee; however, NSP-Minnesota expects sale proceeds to exceed the guaranteed amount.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

The following table presents the guarantee issued and outstanding for NSP-Minnesota:

(Millions of Dollars)	Guarantee Amount	Current Exposure	Term or Expiration Date	Triggering Event
Guarantee of residual value of assets under the Bank of Tokyo-Mitsubishi Capital Corporation Equipment Leasing Agreement	\$ 4.8	\$ —	2019	(a)

(a) Actual fair value of leased assets is less than the guaranteed residual value amount at the end of the lease term.

### Environmental Contingencies

NSP-Minnesota has been or is currently involved with the cleanup of contamination from certain hazardous substances at several sites. In many situations, NSP-Minnesota believes it will recover some portion of these costs through insurance claims. Additionally, where applicable, NSP-Minnesota is pursuing, or intends to pursue, recovery from other PRPs and through the regulated rate process. New and changing federal and state environmental mandates can also create added financial liabilities for NSP-Minnesota, which are normally recovered through the regulated rate process. To the extent any costs are not recovered through the options listed above, NSP-Minnesota would be required to recognize an expense.

**Site Remediation** — Various federal and state environmental laws impose liability, without regard to the legality of the original conduct, 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 or other parties have caused environmental contamination. Environmental contingencies could arise from various situations, including sites of former manufactured gas plants (MGPs) operated by NSP-Minnesota, its predecessors, or other entities; and third-party sites, such as landfills, for which NSP-Minnesota is alleged to be a PRP that sent wastes to that site.

#### MGP Sites

**Fargo, N.D. MGP Site** — In May 2015, underground pipes, tars and impacted soils were discovered in a right-of-way in Fargo, N.D. that appeared to be associated with a former MGP operated by NSP-Minnesota or prior companies. NSP-Minnesota removed impacted soils and other materials from the right-of-way at that time and commenced an investigation of the historic MGP and adjacent properties (the Fargo MGP Site). Based on the investigation, NSP-Minnesota has recommended that targeted source removal of impacted soils and historic MGP infrastructure should be performed. The North Dakota Department of Health approved NSP-Minnesota's proposed cleanup plan in January 2017. The timing and final scope of remediation is dependent on whether current property owners will agree to provide reasonable access to NSP-Minnesota to perform and implement the approved cleanup plan.

NSP-Minnesota has initiated insurance recovery litigation in North Dakota. The U.S. District Court for the District of North Dakota agreed to the parties' request for a stay of the litigation until May 2017.

As of Dec. 31, 2016 and Dec. 31, 2015, NSP-Minnesota had recorded a liability of \$11.3 million and \$2.7 million, respectively, for the Fargo MGP Site, with the increase due to the remediation activities proposed by NSP-Minnesota. In December 2015, the NDPSC approved NSP-Minnesota's request to defer costs associated with the Fargo MGP Site, resulting in deferral of all investigation and response costs with the exception of approximately 12 percent allocable to the Minnesota jurisdiction. Uncertainties related to the liability recognized include obtaining access to perform the approved remediation, final designs that will be developed to implement the approved cleanup plan and the potential for contributions from entities that may be identified as PRPs.

**Other MGP Sites** — NSP-Minnesota is currently involved in investigating and/or remediating several other MGP sites where regulated materials may have been deposited. NSP-Minnesota has identified four sites where former MGP activities have or may have resulted in site contamination and are under current investigation and/or remediation. At some or all of these MGP sites, there are other parties that may have responsibility for some portion of any remediation. NSP-Minnesota anticipates that the majority of the remediation at these sites will continue through at least 2017. NSP-Minnesota had accrued \$0.2 million for all of these sites at Dec. 31, 2016 and Dec. 31, 2015, respectively. There may be insurance recovery and/or recovery from other PRPs that will offset any costs incurred. NSP-Minnesota anticipates that any amounts spent will be fully recovered from customers.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

## ***Environmental Requirements***

### **Water and Waste**

***Asbestos Removal*** — Some of NSP-Minnesota’s facilities contain asbestos. Most asbestos will remain undisturbed until the facilities that contain it are demolished or removed. NSP-Minnesota has recorded an estimate for final removal of the asbestos as an ARO. It may be necessary to remove some asbestos to perform maintenance or make improvements to other equipment. The cost of removing asbestos as part of other work is not expected to be material and is recorded as incurred as operating expenses for maintenance projects, capital expenditures for construction projects or removal costs for demolition projects.

***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. In 2015, the EPA published a final rule regulating the management and disposal of coal combustion residuals (“CCR” or coal ash) as a nonhazardous waste. In December 2016, the Water Infrastructure Improvements for the Nation Act (WIIN Act) was signed into law, which includes provisions that allow the CCR rule to be implemented through a state or federal based permit program and that give the EPA direct enforcement authority. NSP-Minnesota is in the process of evaluating whether the costs of implementing the CCR rule under the potential federal and/or state permit programs could have a material impact on the results of operations, financial position or cash flows.

In 2015, industry and environmental non-governmental organizations sought judicial review of the final CCR rule. In June 2016, the D.C. Circuit issued an order remanding and vacating certain elements of the rule as a result of partial settlements with these parties. A final court decision is anticipated in the first half of 2017. Until a final decision is reached in the case, it is uncertain whether the litigation or partial settlements will have any significant impact on results of operations, financial position or cash flows on NSP-Minnesota. NSP-Minnesota believes that these associated costs would be recoverable through regulatory mechanisms.

***Federal Clean Water Act (CWA) Effluent Limitations Guidelines (ELG)*** — In 2015, the EPA issued a final ELG rule for power plants that use coal, natural gas, oil or nuclear materials as fuel and discharge treated effluent to surface waters as well as utility-owned landfills that receive coal combustion residuals. NSP-Minnesota has reviewed the final rule and is in the process of evaluating whether the costs of compliance could have a material impact on the results of operations, financial position or cash flows. NSP-Minnesota believes that compliance costs would be recoverable through regulatory mechanisms.

***Federal CWA Section 316(b)*** — Section 316(b) of the federal CWA requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available for minimizing adverse environmental impacts to aquatic species. The EPA published the final 316(b) rule in 2014. The rule prescribes technology for protecting fish that get stuck on plant intake screens (known as impingement) and describes a process for site-specific determinations by each state for sites that must protect the small aquatic organisms that pass through the intake screens into the plant cooling systems (known as entrainment). The timing of compliance with the requirements will vary from plant-to-plant since the new rule does not have a final compliance deadline. NSP-Minnesota estimates the likely cost for complying with impingement requirements may be incurred between 2017 and 2027 and is approximately \$48 million. NSP-Minnesota believes at least six plants could be required by state regulators to make improvements to reduce entrainment. The exact cost of the entrainment improvements is uncertain, but could be up to \$188 million depending on the outcome of certain entrainment studies and cost-benefit analyses. NSP-Minnesota anticipates these costs will be fully recoverable in rates.

***Federal CWA Waters of the United States Rule*** — In June 2015, the EPA and the U.S. Army Corps of Engineers published a final rule that significantly expands the types of water bodies regulated under the CWA and broadens the scope of waters subject to federal jurisdiction. The expansion of the term “Waters of the U.S.” will subject more utility projects to federal CWA jurisdiction, thereby potentially delaying the siting of new generation projects, pipelines, transmission lines and distribution lines, as well as increasing project costs and expanding permitting and reporting requirements. In October 2015, the U.S. Court of Appeals for the Sixth Circuit issued a nationwide stay of the final rule and subsequently ruled that it, rather than the federal district courts, had jurisdiction over challenges to the rule. In January 2017, the U.S. Supreme Court agreed to resolve the dispute as to which court should hear challenges to the rule. A ruling is expected by June 2017.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

**Air**

***Greenhouse Gas (GHG) Emission Standard for Existing Sources (Clean Power Plan or CPP)*** — In 2015, a final rule was published by the EPA for GHG emission standards for existing power plants. Under the rule, states were required to develop implementation plans by September 2016, with the possibility of an extension to September 2018, or submit to a federal plan for the state prepared by the EPA. Among other things, the rule requires that state plans include enforceable measures to ensure emissions from existing power plants achieve the EPA’s state-specific interim (2022-2029) and final (2030 and thereafter) emission performance targets. The CPP was challenged by multiple parties in the D.C. Circuit Court. In January 2016, the D.C. Circuit Court denied requests to stay the effectiveness of the rule. In February 2016, the U.S. Supreme Court issued an order staying the final CPP rule. In September 2016, the D.C. Circuit Court heard oral arguments in the consolidated challenges to the CPP. The stay will remain in effect until the D.C. Circuit Court reaches its decision and the U.S. Supreme Court either declines to review the lower court’s decision or reaches a decision of its own. During the pendency of the stay, states are not required to submit implementation plans and the EPA will not enforce deadlines or issue a federal plan for any state. All states served by NSP-Minnesota have suspended formal planning efforts.

NSP-Minnesota has undertaken a number of initiatives that reduce GHG emissions and respond to state renewable and energy efficiency goals. The CPP could require additional emission reductions in states in which NSP-Minnesota operates. If state plans do not provide credit for the investments NSP-Minnesota has already made to reduce GHG emissions, or if they require additional initiatives or emission reductions, then their requirements would potentially impose additional substantial costs. Until NSP-Minnesota has more information about state implementation plan or the EPA finalizes its proposed federal plan for the states that do not develop related plans, NSP-Minnesota cannot predict the costs of compliance with the final rule once it takes effect. NSP-Minnesota believes compliance costs will be recoverable through regulatory mechanisms. If NSP-Minnesota’s regulators do not allow recovery of all or a part of the cost of capital investment or the operating costs incurred to comply with the CPP or cost recovery is not provided in a timely manner, it could have a material impact on results of operations, financial position or cash flows.

***Cross-State Air Pollution Rule (CSAPR)*** — CSAPR addresses long range transport of particulate matter PM and ozone by requiring reductions in SO<sub>2</sub> and NO<sub>x</sub> from utilities in the eastern half of the United States, including Minnesota using an emissions trading program.

CSAPR was adopted to address interstate emissions impacting downwind states’ attainment of the 1997 ozone National Ambient Air Quality Standard (NAAQS) and the 1997 and 2006 particulate NAAQS. As the EPA revises NAAQS, it will consider whether to make any further reductions to CSAPR emission budgets and whether to change which states are included in the emissions trading program. In December 2015, the EPA proposed adjustments to CSAPR emission budgets which address attainment of the more stringent 2008 ozone NAAQS. As Minnesota is not regulated under the CSAPR ozone program, this rule did not impact NSP-Minnesota.

***Implementation of the NAAQS for SO<sub>2</sub>*** — The EPA adopted a more stringent NAAQS for SO<sub>2</sub> in 2010. The EPA is requiring states to evaluate areas in three phases. If an area is designated as nonattainment, the states will need to evaluate all SO<sub>2</sub> sources in the area. The state would then submit an implementation plan, which would be due in 18 months, designed to achieve the NAAQS within five years. It is anticipated the areas near NSP-Minnesota’s power plants will be evaluated in the next designation phase, ending December 2017. NSP-Minnesota’s King and Sherco plants already utilize scrubbers to control SO<sub>2</sub> emissions. NSP-Minnesota’s King plant demonstrated compliance with the SO<sub>2</sub> NAAQS as part of their recent permit renewal. In late 2016, NSP-Minnesota submitted air dispersion modeling to the MPCA and the EPA which demonstrated that NSP-Minnesota’s Sherco plant complies with the NAAQS. NSP-Minnesota cannot evaluate the impacts until the designation of nonattainment areas is made and any required state plans are developed. NSP-Minnesota believes that should SO<sub>2</sub> control systems require upgrades for a plant, compliance costs or the costs of alternative cost-effective generation will be recoverable through regulatory mechanisms and therefore does not expect a material impact on results of operations, financial position or cash flows.

***Revisions to the NAAQS for Ozone*** — In 2015, the EPA revised the NAAQS for ozone by lowering the eight-hour standard from 75 parts per billion (ppb) to 70 ppb. In areas where NSP-Minnesota operates, current monitored air quality concentrations comply with the new standard in the Twin Cities Metropolitan Area in Minnesota. In documents issued with the new standard, the EPA projects the Twin Cities Metropolitan Area will meet the new standard. Therefore, NSP-Minnesota does not expect a material impact on results of operations, financial position or cash flows.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

## Asset Retirement Obligations

**Recorded AROs** — AROs have been recorded for property related to the following: electric production (nuclear, steam, wind, other and hydro), electric distribution and transmission, natural gas transmission and distribution, natural gas storage and general property. The electric production obligations include asbestos, ash-containment facilities, radiation sources, storage tanks, control panels and decommissioning. The asbestos recognition associated with electric production includes certain plants. NSP-Minnesota also recognized asbestos obligations for its general office building. AROs also have been recorded for NSP-Minnesota steam production related to ash-containment facilities such as bottom ash ponds, evaporation ponds and solid waste landfills. NSP-Minnesota has also recorded AROs for the retirement and removal of assets at certain wind production facilities for which the land is leased and removal is required by contract.

NSP-Minnesota has recognized an ARO for the retirement costs of natural gas mains and lines and for the removal of electric transmission and distribution equipment, which consists of many small potential obligations associated with polychlorinated biphenyls (PCBs), mineral oil, storage tanks, lithium batteries, mercury and street lighting lamps. The electric and common general AROs include small obligations related to storage tanks, radiation sources and office buildings.

In April 2015, the EPA published the final rule regulating the management and disposal of coal combustion byproducts (e.g., coal ash) as a nonhazardous waste to the Federal Register. The rule became effective in October 2015. The estimated costs to comply with the final rule were incorporated into the cash flow revisions in 2015.

For the nuclear assets, the ARO is associated with the decommissioning of the NSP-Minnesota nuclear generating plants, Monticello and PI. See Note 10 for further discussion of nuclear obligations.

A reconciliation of NSP-Minnesota's AROs for the years ended Dec. 31, 2016 and 2015 is as follows:

(Thousands of Dollars)	Beginning Balance Jan. 1, 2016	Liabilities Recognized	Liabilities Settled	Accretion	Cash Flow Revisions <sup>(b)</sup>	Ending Balance Dec. 31, 2016
<b>Electric plant</b>						
Nuclear production decommissioning	\$ 2,141,024	\$ —	\$ —	\$ 108,298	\$ —	\$ 2,249,322
Wind production	69,654	17,305 <sup>(a)</sup>	—	3,147	—	90,106
Steam production ash containment	58,688	—	(6,271)	1,737	(12,415)	41,739
Steam, hydro and other production asbestos	25,692	—	—	1,039	—	26,731
Electric distribution	5,427	—	—	197	—	5,624
Steam, hydro and other production miscellaneous	1,663	431	—	63	(636)	1,521
Electric transmission	186	—	—	7	—	193
Steam production radiation sources	67	—	—	4	—	71
<b>Natural gas plant</b>						
Gas transmission and distribution	27,397	—	—	1,103	7,271	35,771
Gas storage asbestos	—	185	—	1	—	186
<b>Common and other property</b>						
Common general plant asbestos	551	—	—	28	—	579
Common miscellaneous	743	—	—	27	(46)	724
<b>Total liability</b>	<b>\$ 2,331,092</b>	<b>\$ 17,921</b>	<b>\$ (6,271)</b>	<b>\$ 115,651</b>	<b>\$ (5,826)</b>	<b>\$ 2,452,567</b>

(a) The liability recognized relates to the Courtenay Wind Farm which was placed in service during 2016.

(b) In 2016, AROs were revised for changes in estimated cash flows and the timing of those cash flows.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

The aggregate fair value of NSP-Minnesota's legally restricted assets, for purposes of funding future nuclear decommissioning, was \$1.9 billion as of Dec. 31, 2016, consisting of external investment funds.

(Thousands of Dollars)	Beginning Balance Jan. 1, 2015	Liabilities Recognized	Liabilities Settled	Accretion	Cash Flow Revisions <sup>(b)</sup>	Ending Balance Dec. 31, 2015
<b>Electric plant</b>						
Nuclear production decommissioning	\$ 2,037,947	\$ —	\$ —	\$ 103,077	\$ —	\$ 2,141,024
Wind production	36,165	31,085 <sup>(a)</sup>	—	1,760	644	69,654
Steam production ash containment	63,730	—	—	1,878	(6,920)	58,688
Steam, hydro and other production asbestos	13,839	4,002	(130)	784	7,197	25,692
Electric distribution	5,048	—	—	183	196	5,427
Steam, hydro and other production miscellaneous	1,668	—	(143)	62	76	1,663
Electric transmission	180	—	—	6	—	186
Steam production radiation sources	55	—	—	4	8	67
<b>Natural gas plant</b>						
Gas transmission and distribution	26,362	—	—	1,035	—	27,397
<b>Common and other property</b>						
Common general plant asbestos	505	—	—	27	19	551
Common miscellaneous	675	—	—	24	44	743
Total liability	<u>\$ 2,186,174</u>	<u>\$ 35,087</u>	<u>\$ (273)</u>	<u>\$ 108,840</u>	<u>\$ 1,264</u>	<u>\$ 2,331,092</u>

(a) The liability recognized relates to the Pleasant Valley and Border Wind Farms which were placed in service during 2015.

(b) In 2015, AROs were revised for changes in estimated cash flows and the timing of those cash flows. Changes in the asbestos and ash containment AROs were mainly related to updated cost estimates.

The aggregate fair value of NSP-Minnesota's legally restricted assets, for purposes of funding future nuclear decommissioning, was \$1.7 billion as of Dec. 31, 2015, consisting of external investment funds.

**Indeterminate AROs** — Outside of the known and 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 amount of asbestos or cost of removal could be determined as of Dec. 31, 2016. Therefore, an ARO has not been recorded for these facilities.

### Nuclear Insurance

On Dec. 31, 2016, NSP-Minnesota's public liability for claims resulting from any nuclear incident was limited to \$13.4 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota had secured \$375 million of coverage for its public liability exposure with a pool of insurance companies. The remaining \$13.0 billion of exposure was funded by the Secondary Financial Protection Program, available from assessments by the federal government in case of a nuclear accident. On Jan. 1, 2017, the available insurance limit was increased from \$375 million to \$450 million. This increase in limit occurs periodically and the Price-Anderson amendment to the Atomic Energy Act requires purchasing the full available limit. On Jan. 1, 2017 this \$450 million limit was secured from the insurance pool. NSP-Minnesota is subject to assessments of up to \$127.3 million per reactor per accident for each of its three licensed reactors, to be applied for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is \$19.0 million per reactor per incident during any one year. These maximum assessment amounts are both subject to inflation adjustment by the NRC and state premium taxes. The NRC's last adjustment was effective September 2013.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Ltd. (NEIL). The coverage limits are \$2.3 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage, including the cost of replacement power obtained during certain 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 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. However, in each calendar year, NSP-Minnesota could be subject to maximum assessments of approximately \$19.8 million for business interruption insurance and \$43.0 million for property damage insurance if losses exceed accumulated reserve funds.

### Legal Contingencies

NSP-Minnesota is involved in various litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that 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.

### Other Contingencies

See Note 8 for further discussion.

## 10. Nuclear Obligations

**Fuel Disposal** — NSP-Minnesota is responsible for temporarily storing used or spent nuclear fuel from its nuclear plants. The DOE is responsible for permanently storing spent fuel from NSP-Minnesota's nuclear plants as well as from other U.S. nuclear plants, but no such facility is yet available. NSP-Minnesota has funded its portion of the DOE's permanent disposal program since 1981. Through May 2014, the fuel disposal fees were based on a charge of 0.1 cent per KWh sold to customers from nuclear generation. Since that time, the DOE has set the fee to zero.

There were no DOE fuel disposal assessments in 2016 or 2015.

NSP-Minnesota has its own temporary on-site storage facilities for spent fuel at its Monticello and PI nuclear plants, which consist of storage pools and dry cask facilities at both sites. The amount of spent fuel storage capacity is determined by the NRC and the MPUC. The Monticello dry-cask storage facility currently stores 16 of the 30 authorized canisters, and the PI dry-cask storage facility currently stores 40 of the 64 authorized casks.

**Regulatory Plant Decommissioning Recovery** — Decommissioning activities related to 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. The MPUC most recently approved NSP-Minnesota's 2014 nuclear decommissioning study in October 2015. This cost study quantified decommissioning costs in 2014 dollars and utilized escalation rates of 4.36 percent per year for plant removal activities, and 3.36 percent for spent fuel management and site restoration activities over a 60-year decommissioning scenario.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

The total obligation for decommissioning is expected to be funded 100 percent by the external decommissioning trust fund when decommissioning commences. NSP-Minnesota's most recently approved decommissioning study resulted in an annual funding requirement of \$14 million to be recovered in utility customer rates which started in 2016. This cost study assumes the external decommissioning fund will earn an after-tax return between 5.23 percent and 6.30 percent. Realized and unrealized gains on fund investments are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs.

As of Dec. 31, 2016, NSP-Minnesota has accumulated \$1.9 billion of assets held in external decommissioning trusts. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation based on parameters established in the most recently approved decommissioning study. Xcel Energy believes future decommissioning costs, if necessary, will continue to be recovered in customer rates. The amounts presented below were prepared on a regulatory basis, and are not recorded in the financial statements for the ARO.

(Thousands of Dollars)	Regulatory Basis	
	2016	2015
Estimated decommissioning cost obligation from most recently approved study (in 2014 dollars)	\$ 3,012,342	\$ 3,012,342
Effect of escalating costs (to 2016 and 2015 dollars, respectively, at 4.36/3.36 percent)	258,278	126,464
Estimated decommissioning cost obligation (in current dollars)	3,270,620	3,138,806
Effect of escalating costs to payment date (4.36/3.36 percent)	7,934,874	8,066,688
Estimated future decommissioning costs (undiscounted)	11,205,494	11,205,494
Effect of discounting obligation (using average risk-free interest rate of 3.25 percent and 3.01 percent for 2016 and 2015, respectively)	(7,068,362)	(6,891,392)
Discounted decommissioning cost obligation	<u>\$ 4,137,132</u>	<u>\$ 4,314,102</u>
Assets held in external decommissioning trust	\$ 1,860,762	\$ 1,724,150
Underfunding of external decommissioning fund compared to the discounted decommissioning obligation	2,276,370	2,589,952

Calculations and data used by the regulator in approving company rates are useful in assessing future cash flows. The 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. The following table provides a reconciliation of the discounted decommissioning cost obligation - regulated basis to the ARO recorded in accordance with GAAP:

(Thousands of Dollars)	2016	2015
Discounted decommissioning cost obligation - regulated basis	\$ 4,137,132	\$ 4,314,102
Differences in discount rate and market risk premium	(1,043,655)	(1,275,438)
Operating costs not included for GAAP	(844,155)	(897,640)
Nuclear production decommissioning ARO - GAAP	<u>\$ 2,249,322</u>	<u>\$ 2,141,024</u>

Decommissioning expenses recognized as a result of regulation for the years ending Dec. 31 were:

(Thousands of Dollars)	2016	2015
Annual decommissioning recorded as depreciation expense: (a) (b)	\$ 20,372	\$ 6,862

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

(b) Decommissioning expense in 2016 includes Minnesota's retail jurisdiction annual funding requirement of approximately \$14 million. The 2015 expense was offset by the DOE settlement refund.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

The 2014 nuclear decommissioning filing approved in 2015 has been used for the regulatory presentation for both 2015 and 2016.

## 11. Regulatory Assets and Liabilities

NSP-Minnesota's financial statements are prepared in accordance with the applicable accounting guidance, as discussed in Note 1. Under this guidance, 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. Any portion of the business that is not rate regulated cannot establish regulatory assets and liabilities. If changes in the utility industry or the business of NSP-Minnesota no longer allow for the application of regulatory accounting guidance under GAAP, NSP-Minnesota would be required to recognize the write-off of regulatory assets and liabilities in net income or OCI.

The components of regulatory assets shown on the balance sheets of NSP-Minnesota at Dec. 31, 2016 and 2015 are:

(Thousands of Dollars)	Dec. 31, 2016	Dec. 31, 2015
<b>Regulatory Assets</b>		
Asset retirement recovery	\$ 2,016,555	\$ 1,851,864
Pension and retiree medical obligations <sup>(a)</sup>	433,227	378,580
Theoretical depreciation reserve surplus	287,913	237,420
Recoverable deferred taxes on AFUDC recorded in plant	206,729	204,089
Contract valuation adjustments <sup>(b)</sup>	117,480	134,103
Nuclear refueling outage costs	64,946	96,458
Renewable resources and environmental initiatives	49,805	59,494
Purchased power contracts costs	41,804	41,536
Conservation programs <sup>(c)</sup>	21,203	9,710
Sherco Unit 3 Deferral	9,157	9,596
Other	49,042	35,197
Other regulatory assets	<u>\$ 3,297,861</u>	<u>\$ 3,058,047</u>

(a) Includes \$241.0 million and \$257.5 million for the regulatory recognition of pension expense at Dec. 31, 2016 and 2015, respectively. Also included are \$1.0 million and \$0.6 million of regulatory assets related to the non-qualified pension plan at Dec. 31, 2016 and 2015, respectively.

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

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

The components of regulatory liabilities shown on the balance sheets of NSP-Minnesota at Dec. 31, 2016 and 2015 are:

(Thousands of Dollars)	Dec. 31, 2016	Dec. 31, 2015
<b>Regulatory Liabilities</b>		
Plant removal costs	\$ 1,502,602	\$ 1,468,068
Unrealized gains on nuclear decommissioning trust investments	239,373	164,897
Deferred income tax adjustment	29,253	27,181
Investment tax credit deferrals	25,577	24,968
DOE Settlement	13,833	12,755
Contract valuation adjustments <sup>(a)</sup>	15,321	12,274
Deferred electric energy costs	18,872	9,112
Other	23,626	14,138
Other regulatory liabilities <sup>(b)</sup>	<u>\$ 1,868,457</u>	<u>\$ 1,733,393</u>

(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) Revenue subject for refund of \$43.5 million and \$62.1 million for 2016 and 2015, respectively, is included in other current liabilities.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

At Dec. 31, 2016 and 2015, approximately \$73 million and \$89 million of NSP-Minnesota's regulatory assets represented past expenditures not currently earning a return, respectively. This amount primarily includes PI EPU costs and recoverable purchased natural gas and electric energy costs.

## 12. Other Comprehensive Income

Changes in accumulated other comprehensive (loss) income, net of tax, for the years ended Dec. 31, 2016 and 2015 were as follows:

(Thousands of Dollars)	Year Ended Dec. 31, 2016			
	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	\$ (19,090)	\$ 105	\$ (2,096)	\$ (21,081)
Other comprehensive income (loss) before reclassifications	5	—	(661)	(656)
Losses reclassified from net accumulated other comprehensive loss	877	—	77	954
Net current period other comprehensive income (loss)	882	—	(584)	298
Accumulated other comprehensive (loss) income at Dec. 31	\$ (18,208)	\$ 105	\$ (2,680)	\$ (20,783)

(Thousands of Dollars)	Year Ended Dec. 31, 2015			
	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	\$ (19,909)	\$ 105	\$ (1,010)	\$ (20,814)
Other comprehensive loss before reclassifications	(39)	—	(1,061)	(1,100)
Losses (gains) reclassified from net accumulated other comprehensive loss	858	—	(25)	833
Net current period other comprehensive income (loss)	819	—	(1,086)	(267)
Accumulated other comprehensive (loss) income at Dec. 31	\$ (19,090)	\$ 105	\$ (2,096)	\$ (21,081)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Reclassifications from accumulated other comprehensive (loss) income for the years ended Dec. 31, 2016 and 2015 were as follows:

(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss	
	Year Ended Dec. 31, 2016	Year Ended Dec. 31, 2015
Losses (gains) on cash flow hedges:		
Interest rate derivatives	\$ 1,392 <sup>(a)</sup>	\$ 1,385 <sup>(a)</sup>
Vehicle fuel derivatives	104 <sup>(b)</sup>	73 <sup>(b)</sup>
<b>Total, pre-tax</b>	<b>1,496</b>	<b>1,458</b>
Tax benefit	(619)	(600)
<b>Total, net of tax</b>	<b>877</b>	<b>858</b>
Defined benefit pension and postretirement losses (gains):		
Amortization of net loss	332 <sup>(c)</sup>	156 <sup>(c)</sup>
Prior service cost	(196) <sup>(c)</sup>	(196) <sup>(c)</sup>
<b>Total, pre-tax</b>	<b>136</b>	<b>(40)</b>
Tax benefit	(59)	15
<b>Total, net of tax</b>	<b>77</b>	<b>(25)</b>
<b>Total amounts reclassified, net of tax</b>	<b>\$ 954</b>	<b>\$ 833</b>

(a) Included in interest charges.

(b) Included in operating expenses.

(c) Included in the computation of net periodic pension and postretirement benefit costs. See Note 6 for details regarding these benefit plans.

### 13. Related Party Transactions

The table below contains significant affiliate transactions among the companies and related parties including billings under the Interchange Agreement for the years ended Dec. 31:

(Thousands of Dollars)	2016	2015
Operating revenues:		
Electric	\$ 475,534	\$ 473,099
Gas	41	45
Operating expenses:		
Purchased power	63,018	70,504
Transmission expense	107,466	92,751
Other operating expenses — paid to Xcel Energy Services Inc.	512,967	439,144
Interest expense	49	238
Interest income	—	94

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

(Thousands of Dollars)	2016		2015	
	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Wisconsin	\$ 18,567	\$ —	\$ 18,268	\$ —
PSCo	—	7,669	—	4,419
SPS	—	935	—	1,066
Other subsidiaries of Xcel Energy Inc.	32,824	51,029	25,972	54,300
	\$ 51,390	\$ 59,633	\$ 44,240	\$ 59,785

#### 14. Supplementary Cash Flow Data

(Thousands of Dollars)	2016	2015
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	\$ (203,191)	\$ (185,553)
Cash (paid) received for income taxes, net	(39,013)	53,343
Supplemental disclosure of non-cash investing transactions:		
Property, plant and equipment additions in accounts payable	\$ 103,459	\$ 111,675

#### 15. 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 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, 2016 and 2015. 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 amount of \$3,209 and in the credit amount of \$30,910 for the year ended Dec. 31 2016 and 2015, 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 9,024 and zero for the year ended Dec. 31, 2016 and 2015, respectively. Due to FERC software limitations, these amounts are reported in Account 548.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Energy storage-related maintenance expenses are recorded in Account 553.1 in accordance with FERC Order No. 784 in the amount of \$78,057 and \$109,218 for the year ended Dec. 31, 2016 and 2015, respectively. Due to FERC software limitations, these amounts are reported in Account 553.

The following tables present NSP-Minnesota's Energy Storage Operations for small plants as of and for the year ended Dec. 31, 2016, 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 for Storage Operations	Other Expenses
1	Luverne, Minn. Wind2Battery Project	Production	Luverne, Minn.	\$ 4,128,902	\$ 9,024	\$ 78,057	\$ —	\$ 3,209	\$ —

The following tables present NSP-Minnesota's Energy Storage Operations for small plants as of and for the year ended Dec. 31, 2015, 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 for Storage Operations	Other Expenses
1	Luverne, Minn. Wind2Battery Project	Production	Luverne, Minn.	\$ 4,128,902	\$ —	\$ 109,218	\$ —	\$ (30,910)	\$ —



Name of Respondent  
Northern States Power Company (Minnesota)

This Report Is:  
(1)  An Original  
(2)  A Resubmission

Date of Report  
(Mo, Da, Yr)  
04/10/2017

Year/Period of Report  
End of 2016/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	( 19,815,518)	( 93,382)	( 20,814,248)		
2	815,487	43,011	832,501		
3		( 39,099)	( 1,099,591)		
4	815,487	3,912	( 267,090)	356,839,250	356,572,160
5	( 19,000,031)	( 89,470)	( 21,081,338)		
6	( 19,000,031)	( 89,470)	( 21,081,338)		
7	815,200	61,952	954,241		
8		4,504	( 655,612)		
9	815,200	66,456	298,629	488,743,682	489,042,311
10	( 18,184,831)	( 23,014)	( 20,782,709)		

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

**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.

This footnote applies to all of column g.

**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)	16,906,252,830	15,119,858,342
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	2,350,830,141	2,127,144,020
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	19,257,082,971	17,247,002,362
9	Leased to Others		
10	Held for Future Use	5,799,448	5,799,448
11	Construction Work in Progress	509,028,925	397,465,532
12	Acquisition Adjustments	222,385	222,385
13	Total Utility Plant (8 thru 12)	19,772,133,729	17,650,489,727
14	Accum Prov for Depr, Amort, & Depl	7,413,415,120	6,495,262,031
15	Net Utility Plant (13 less 14)	12,358,718,609	11,155,227,696
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	7,030,441,841	6,367,401,231
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	382,750,894	127,638,415
22	Total In Service (18 thru 21)	7,413,192,735	6,495,039,646
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	222,385	222,385
33	Total Accum Prov (equals 14) (22,26,30,31,32)	7,413,415,120	6,495,262,031

Name of Respondent  
Northern States Power Company (Minnesota)

This Report Is:  
(1)  An Original  
(2)  A Resubmission

Date of Report  
(Mo, Da, Yr)  
04/10/2017

Year/Period of Report  
End of 2016/Q4

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
1,233,395,019				552,999,469	3
					4
					5
77,839,777				145,846,344	6
					7
1,311,234,796				698,845,813	8
					9
					10
14,749,145				96,814,248	11
					12
1,325,983,941				795,660,061	13
580,752,113				337,400,976	14
745,231,828				458,259,085	15
					16
					17
575,528,047				87,512,563	18
					19
					20
5,224,066				249,888,413	21
580,752,113				337,400,976	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
580,752,113				337,400,976	33

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

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

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

Intangible Plant	\$ 72,914,921
Nuclear Production Plant	52,764,816
Hydraulic Production Plant-Conventional	1,023,166
Other Production	935,512
Total Amort of Other Utility Plant - Electric	<u>\$ 127,638,415</u>

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

The amortization of other utility plant within account 115 includes the following:

Transmission	\$ 222,385
--------------	------------

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	16,974,576	11,772,776
3	Nuclear Materials	120,277,680	102,643,556
4	Allowance for Funds Used during Construction	11,339,804	9,797,013
5	(Other Overhead Construction Costs, provide details in footnote)	134,986	53,393
6	SUBTOTAL (Total 2 thru 5)	148,727,046	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		67,814,798
9	In Reactor (120.3)	525,918,125	68,694,131
10	SUBTOTAL (Total 8 & 9)	525,918,125	
11	Spent Nuclear Fuel (120.4)	1,772,605,603	67,954,678
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	2,063,654,320	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	383,596,454	
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)		

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance End of Year (f)	Line No.
Amortization (d)	Other Reductions (Explain in a footnote) (e)		
			1
	9,335,205	19,412,147	2
	51,629,045	171,292,191	3
	6,496,441	14,640,376	4
	7,644	180,735	5
		205,525,449	6
			7
	67,814,798		8
	67,954,678	526,657,578	9
		526,657,578	10
	973,156	1,839,587,125	11
			12
-116,981,546		2,180,635,866	13
		391,134,286	14
			15
			16
			17
			18
			19
			20
			21
			22

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

**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 Administration 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

**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	236,170,200	255,644
4	(303) Miscellaneous Intangible Plant	113,270,857	1,901,697
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	349,441,057	2,157,341
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	8,497,630	
9	(311) Structures and Improvements	288,408,493	242,993
10	(312) Boiler Plant Equipment	1,409,201,405	16,808,206
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	295,303,385	20,940,947
13	(315) Accessory Electric Equipment	183,259,902	704,329
14	(316) Misc. Power Plant Equipment	53,933,050	110,708
15	(317) Asset Retirement Costs for Steam Production	43,610,117	-19,321,699
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	2,282,213,982	19,485,484
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	1,154,813	607,496
19	(321) Structures and Improvements	497,012,122	39,529,177
20	(322) Reactor Plant Equipment	1,525,075,172	65,349,260
21	(323) Turbogenerator Units	587,193,232	5,504,787
22	(324) Accessory Electric Equipment	453,880,670	7,170,937
23	(325) Misc. Power Plant Equipment	198,833,155	10,532,255
24	(326) Asset Retirement Costs for Nuclear Production	482,670,802	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	3,745,819,966	128,693,912
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	1,693,076	
28	(331) Structures and Improvements	1,387,646	
29	(332) Reservoirs, Dams, and Waterways	10,590,829	215,855
30	(333) Water Wheels, Turbines, and Generators	10,038,998	
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)	27,028,345	215,855
36	D. Other Production Plant		
37	(340) Land and Land Rights	19,867,150	2,090,672
38	(341) Structures and Improvements	250,533,773	8,500,336
39	(342) Fuel Holders, Products, and Accessories	88,420,592	-31,817
40	(343) Prime Movers		
41	(344) Generators	1,906,841,312	270,947,705
42	(345) Accessory Electric Equipment	250,854,718	18,100,417
43	(346) Misc. Power Plant Equipment	31,335,364	36,400
44	(347) Asset Retirement Costs for Other Production	60,097,940	17,736,282
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	2,607,950,849	317,379,995
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	8,663,013,142	465,775,246

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	<b>3. TRANSMISSION PLANT</b>		
48	(350) Land and Land Rights	148,243,356	4,464,661
49	(352) Structures and Improvements	78,984,222	24,136,683
50	(353) Station Equipment	1,144,133,400	34,040,538
51	(354) Towers and Fixtures	118,506,371	125,488
52	(355) Poles and Fixtures	1,235,590,730	94,796,313
53	(356) Overhead Conductors and Devices	507,473,281	24,812,943
54	(357) Underground Conduit	25,647,719	262,419
55	(358) Underground Conductors and Devices	30,951,192	-240,619
56	(359) Roads and Trails	173,429	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	<b>TOTAL Transmission Plant (Enter Total of lines 48 thru 57)</b>	<b>3,289,703,700</b>	<b>182,398,426</b>
59	<b>4. DISTRIBUTION PLANT</b>		
60	(360) Land and Land Rights	16,462,047	1,328
61	(361) Structures and Improvements	46,102,148	1,696,145
62	(362) Station Equipment	582,605,519	38,300,695
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	371,073,684	21,815,167
65	(365) Overhead Conductors and Devices	418,881,334	20,931,137
66	(366) Underground Conduit	261,465,818	24,409,521
67	(367) Underground Conductors and Devices	1,065,018,642	51,970,458
68	(368) Line Transformers	428,125,494	24,707,609
69	(369) Services	289,855,163	7,273,137
70	(370) Meters	110,565,337	5,783,519
71	(371) Installations on Customer Premises	22,705,174	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	60,791,096	9,571,277
74	(374) Asset Retirement Costs for Distribution Plant	3,770,269	
75	<b>TOTAL Distribution Plant (Enter Total of lines 60 thru 74)</b>	<b>3,677,421,725</b>	<b>206,459,993</b>
76	<b>5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT</b>		
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	<b>TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)</b>		
85	<b>6. GENERAL PLANT</b>		
86	(389) Land and Land Rights	4,438,920	
87	(390) Structures and Improvements	63,355,235	561,932
88	(391) Office Furniture and Equipment	49,450,745	13,285,007
89	(392) Transportation Equipment	145,089,255	5,003,012
90	(393) Stores Equipment	1,724,162	
91	(394) Tools, Shop and Garage Equipment	77,082,857	6,427,414
92	(395) Laboratory Equipment	3,539,038	145,418
93	(396) Power Operated Equipment	42,091,882	3,871,307
94	(397) Communication Equipment	48,963,089	29,170,818
95	(398) Miscellaneous Equipment	2,866,815	
96	<b>SUBTOTAL (Enter Total of lines 86 thru 95)</b>	<b>438,601,998</b>	<b>58,464,908</b>
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	<b>TOTAL General Plant (Enter Total of lines 96, 97 and 98)</b>	<b>438,601,998</b>	<b>58,464,908</b>
100	<b>TOTAL (Accounts 101 and 106)</b>	<b>16,418,181,622</b>	<b>915,255,914</b>
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	<b>TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)</b>	<b>16,418,181,622</b>	<b>915,255,914</b>



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
			152,708,017		48
34,538			103,086,367		49
718,155		3,993,428	1,181,449,211		50
			118,631,859		51
-169,019			1,330,556,062		52
-417,878			532,704,102		53
			25,910,138		54
			30,710,573		55
			173,429		56
					57
165,796		3,993,428	3,475,929,758		58
					59
			16,463,375		60
407		1,392,336	49,190,222		61
3,043,289		7,841,275	625,704,200		62
					63
605,770			392,283,081		64
2,883,108			436,929,363		65
137,181		160,973	285,899,131		66
2,301,580			1,114,687,520		67
9,918,380			442,914,723		68
885,757			296,242,543		69
5,082,204			111,266,652		70
			22,705,174		71
					72
293,379			70,068,994		73
			3,770,269		74
25,151,055		9,394,584	3,868,125,247		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			4,438,920		86
373,209			63,543,958		87
2,743,835			59,991,917		88
683,544			149,408,723		89
75,371			1,648,791		90
2,209,131			81,301,140		91
474,723			3,209,733		92
828,369			45,134,820		93
207,833		71,334	77,997,408		94
142,974			2,723,841		95
7,738,989		71,334	489,399,251		96
					97
					98
7,738,989		71,334	489,399,251		99
99,894,520		13,459,346	17,247,002,362		100
					101
					102
					103
99,894,520		13,459,346	17,247,002,362		104

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
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	\$ 84,618,861
Account 348 Energy Storage, Equipment - Production	4,128,902
	<u>\$ 88,747,763</u>

**Schedule Page: 204 Line No.: 58 Column: g**

Transmission Serving Production

	Beginning Balance	Additions	Retirements	Adjustments	Transfers	Ending Balance
Account 350 - Land & Land Rights	157,969	0	0	0	0	157,969
Account 352 - Structures & Improvements	10,460,207	3,747,063	(2,644)	0	0	14,204,626
Account 353 - Station Equipment	53,625,016	5,072,148	0	0	0	58,697,164
Account 354 - Towers & Fixtures	5,136,416	125,488	0	0	0	5,261,904
Account 355 - Poles & Fixtures	4,239,354	8,055,576	980,704	0	0	13,275,634
Account 356 - Overhead Conductors & Devices	429,655	0	418,313	0	0	847,968

**Schedule Page: 204 Line No.: 75 Column: g**

Distribution Serving Production

	Beginning Balance	Additions	Retirements	Adjustments	Transfers	Ending Balance
Account 361 - Structures & Improvements	838,281	0	0	0	0	838,281
Account 362 - Station Equipment	2,692,338	0	0	0	0	2,692,338

Name of Respondent

Northern States Power Company (Minnesota)

This Report Is:

(1)  An Original

(2)  A Resubmission

Date of Report

(Mo, Da, Yr)

04/10/2017

Year/Period of Report

End of 2016/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					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47	TOTAL				

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of \$250,000 or more. Group other items of property held for future use.
2. For property having an original cost of \$250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23	Nuclear Dry Fuel Canisters, Monticello Nuc Gen Plant	2014	2018	5,799,448
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			5,799,448

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/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.

**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	BSSB-345kV Non Shared Line	47,372,511
2	BDS0C Black Dog U6 Simple Cycl	41,792,392
3	PI-9 TN-40 Casks(39-47)	36,429,961
4	PI-NFPA 805 Fire Model	18,401,835
5	PI U1 Generator Replacemnt LCM	11,747,704
6	PI U2 HDTP Speed Control Upgr	11,142,198
7	MNGP 2018 Dry Fuel Storage Loa	10,251,565
8	MNGP DAS & PPCS Rplc	9,591,721
9	MNGP Hardened Vents & Filters	8,467,843
10	NSPM0799 UG Reloc Redwing Brid	8,027,444
11	ADMS SW MN	5,888,130
12	MN Frame Relay Comm	5,824,883
13	MN-Dist Fleet New Unit Purchase EI	5,533,003
14	SHC3C Motor Control Sys PLC Re	5,323,848
15	BSSB-Brooking Non Shared Sub	5,256,991
16	PI NSSS/BOP Annunciator Repl	4,967,189
17	PI NFPA 805 -05 Incipient Det	4,569,571
18	Yankee Reactor Sub	4,361,252
19	PI NFPA 805-24 CT11CT12 Brkrs	4,029,086
20	PI Proc Controls Repl	3,463,661
21	PI Sfgds CL Pump Redesign	3,286,339
22	GSL to PKL Line Permit Pre Con	3,229,353
23	Frame Relay Replacement - NSPM	3,138,469
24	MNUG Extension-MN	2,999,203
25	MN-Solar Garden Sub Work	2,810,931
26	Purch Sub Frame Relay Equip MN	2,668,601
27	Dean Lake Substation	2,616,062
28	Install feeder at new Hazeltin	2,546,249
29	PI NFPA 805-10 Loss OCT 4KV Br	2,538,471
30	Northwest Solar Gardens Ext	2,513,926
31	PI AFW Pump Room Cooling	2,358,180
32	H081 Wind Hawks Nest Lake Sub	2,313,791
33	Fleet New Units 2016 EI Trans	2,256,415
34	PI 121 CT Deck Header Valves	2,217,478
35	PI 1R Transformer Replacement	2,040,581
36	MT TSTF-523 Vent Installation	1,966,069
37	Inst BYT#2 28 MVA	1,920,066
38	MNOH Rebuilds-MN	1,916,186
39	SHC3C Repl U3 Boiler Fin Super	1,849,953
40	QRY-New 115kV Line TermSub	1,822,947
41	Minot Load Serving Line Permit	1,793,718
42	PI 2M 2RS 2RX Transformer Re	1,785,106
43	TOTAL	397,465,532

**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	NSPM Physical Security Comm	1,726,582
2	PI NFPA 805-03 U1 Train B AFW	1,677,611
3	SHC1C U1 Turbine Replacement	1,670,739
4	Line 0794 69kV DGC-WSU line	1,666,212
5	CAPX BRK BTF STF CHX1360 Land	1,657,985
6	SHC3C Boiler Section Repl 2020	1,656,599
7	Chestnut Pressure Control Unit	1,651,022
8	MNGP Rplc NON 1E Inverter, Y-9	1,645,190
9	PI NFPA 805-02 U2 Train A AFW	1,593,772
10	Solar Garden Ext - WBL	1,580,266
11	PI 4.16 KV Bus Modifications	1,573,937
12	NSPM-Accelerated URD Cable Rep	1,566,758
13	GIST-IV Computer Software NSPM	1,527,779
14	Minnesota-Sub Capac Reinforcem	1,432,507
15	MNGP Rplc one RECIR M/G Gen	1,384,272
16	PI DC Pnl 11122122 Switches	1,373,142
17	Rebuild Manholes along Jackson	1,336,383
18	CAPX BRK BTF STF LCX 1066 Land	1,329,196
19	MNGP Obsolete EQ RFO 28	1,292,554
20	Install Falls Sub UG Feeders	1,257,303
21	BDS0C Municipal Sewer Line	1,250,798
22	SHC3C Turbine EHC Controls Rep	1,242,029
23	PI Emerg Resp Equipment FLEX	1,235,943
24	PI NFPA 805-14 RL Sw AFW Rm	1,219,238
25	Install Eastwood 081 and 082	1,149,896
26	MNGP Tools & Equipment	1,125,555
27	PI Namco Limit Switch Repl	1,080,778
28	Baytown115kV BKR Sub	1,063,625
29	Relocate Ductline MH & Feeder	1,062,428
30	Aurora Solar Sub Reinforcement	1,041,958
31	PI NFPA 805-01 U1 Train A AFW	1,021,998
32		
33	Minor Projects	49,340,595
34		
35		
36		
37		
38		
39		
40		
41	Footnote from Page 106b	
42		
43	TOTAL	397,465,532

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

**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.

**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	5,967,889,247	5,967,889,247		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	476,240,925	476,240,925		
4	(403.1) Depreciation Expense for Asset Retirement Costs	30,175,864	30,175,864		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	14,303,962	14,303,962		
7	Other Clearing Accounts	161,247	161,247		
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	520,881,998	520,881,998		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	71,706,185	71,706,185		
13	Cost of Removal	75,962,359	75,962,359		
14	Salvage (Credit)	6,675,864	6,675,864		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	140,992,680	140,992,680		
16	Other Debit or Cr. Items (Describe, details in footnote):	29,151,804	29,151,804		
17					
18	Book Cost or Asset Retirement Costs Retired	-9,529,138	-9,529,138		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	6,367,401,231	6,367,401,231		

**Section B. Balances at End of Year According to Functional Classification**

20	Steam Production	1,348,133,372	1,348,133,372		
21	Nuclear Production	1,718,654,912	1,718,654,912		
22	Hydraulic Production-Conventional	10,896,481	10,896,481		
23	Hydraulic Production-Pumped Storage				
24	Other Production	721,082,185	721,082,185		
25	Transmission	824,473,972	824,473,972		
26	Distribution	1,547,737,277	1,547,737,277		
27	Regional Transmission and Market Operation				
28	General	196,423,032	196,423,032		
29	TOTAL (Enter Total of lines 20 thru 28)	6,367,401,231	6,367,401,231		

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

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

Net change in RWIP	\$ 29,151,726
Net Transfers	91
Other	(13)
Total	<u>\$ 29,151,804</u>

**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	\$ 33,633,577
---------------------------------	---------------

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

Distribution Serving Production	\$ 2,048,929
---------------------------------	--------------

**Schedule Page: 219 Line No.: 29 Column: c**

	"Non-Legal" ARO Balances
Steam Plant	\$ 69,392,007
Nuclear Plant	(92,194,831)
Hydraulic Production-Conventional	1,628,288
Other Production	24,498,748
Transmission	98,598,344
Distribution	229,479,891
General	(785,869)
Total	<u>\$ 330,616,578</u>

**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			299,765
4	Undistributed earnings (loss) since acquisition			-3,278,643
5	SUBTOTAL			1,041,122
6				
7	NSP NUCLEAR CO.			
8	Contributed Capital			963,198
9	Undistributed earnings (loss) since acquisition			548,740
10	SUBTOTAL			1,511,938
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 \$	5,382,963	TOTAL	2,553,060

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 from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if 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
	100,000	399,765		3
-84,203		-3,362,846		4
-84,203	100,000	1,056,919		5
				6
				7
		963,198		8
4,250		552,990		9
4,250		1,516,188		10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
-79,953	100,000	2,573,107		42

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

**Schedule Page: 224 Line No.: 3 Column: f**  
 Contribution of capital from parent company.

**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)	107,654,333	100,686,129	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)	19,105,622	24,596,470	Electric & Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	179,817,532	188,937,211	Electric
8	Transmission Plant (Estimated)	309,594	532,649	Electric
9	Distribution Plant (Estimated)	3,218,545	3,481,198	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	-2,308,923	-4,260,077	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	200,142,370	213,287,451	
13	Merchandise (Account 155)	738,863	942,563	
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)	308,535,566	314,916,143	

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

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

Includes a credit of \$2,992,149 for inventory allocated to Southern Minnesota Municipal Power Agency (41 percent owners of Sherco 3) and a debit of \$683,226 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 \$3,051,287 for inventory allocated to Southern Minnesota Municipal Power Agency (41 percent owners of Sherco 3) and a credit of \$1,208,791 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).

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		2017	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	672,579.00		86,137.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	95,592.00			
5	Returned by EPA	528.00			
6					
7					
8	Purchases/Transfers:				
9	Transfer to SMMPA	-3,667.00			
10					
11					
12					
13					
14					
15	Total	-3,667.00			
16					
17	Relinquished During Year:				
18	Charges to Account 509	20,066.00			
19	Other:				
20	Adjust Balance	80,263.00		-9,455.00	
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	664,703.00		95,592.00	
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	925.00		925.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	925.00			
40	Balance-End of Year			925.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	925.00	77		
45	Gains		77		
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/transfersors 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.

2018		2019		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
86,137.00		86,137.00		1,556,780.00		2,487,770.00		1
								2
								3
						95,592.00		4
						528.00		5
								6
								7
								8
						-3,667.00		9
								10
								11
								12
								13
								14
						-3,667.00		15
								16
								17
						20,066.00		18
								19
-9,455.00		-9,455.00		-313,294.00		-261,396.00		20
								21
								22
								23
								24
								25
								26
								27
								28
95,592.00		95,592.00		1,870,074.00		2,821,553.00		29
								30
								31
								32
								33
								34
								35
925.00		925.00		44,397.00		48,097.00		36
				1,850.00		1,850.00		37
								38
				925.00		1,850.00		39
925.00		925.00		45,322.00		48,097.00		40
								41
								42
								43
				926.00		1,851.00		77 44
								77 45
								46

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

**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, 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.

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		2017	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	18,511.00		14,627.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	17,635.00		17,635.00	
5	Returned by EPA	363.00			
6					
7					
8	Purchases/Transfers:				
9	Transfer to SMMPA	-1,186.00			
10					
11					
12					
13					
14					
15	Total	-1,186.00			
16					
17	Relinquished During Year:				
18	Charges to Account 509	10,276.00			
19	Other:				
20	Adjust Balance	12,357.00		14,627.00	
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	12,690.00		17,635.00	
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/transfersors 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.

2018		2019		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
14,627.00		14,627.00		14,627.00		77,019.00		1
								2
								3
17,635.00		17,635.00				70,540.00		4
						363.00		5
								6
								7
								8
						-1,186.00		9
								10
								11
								12
								13
								14
						-1,186.00		15
								16
								17
						10,276.00		18
								19
14,627.00		14,627.00		-40,873.00		15,365.00		20
								21
								22
								23
								24
								25
								26
								27
								28
17,635.00		17,635.00		55,500.00		121,095.00		29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report End of <u>2016/Q4</u>
---	---	--	--

**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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	None					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

**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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21	Prairie Island	78,884,915		Various	2,967,107	65,060,122
22	Extended Power Uprate project					
23	MPUC Docket No.					
24	E002/CN-08-509					
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	78,884,915			2,967,107	65,060,122

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

**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	<u>1,194,819</u>
	<u>\$ 78,884,915</u>

**Schedule Page: 230 Line No.: 21 Column: e**

Account No. 426.5 - accretion during 2016	\$ (577,259)
Account No. 407 - amortization during 2016	<u>3,544,366</u>
	<u>\$ 2,967,107</u>

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	<b>Transmission Studies</b>				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	<b>Generation Studies</b>				
22	J309 Facility Study	1	561.7	14,456	143
23	J303 Facility Study			18,099	143
24	J385 Facility Study			111,137	143
25	J400 Facility Study	3,460	561.7	42,764	143
26	C019 Facility Study			18,092	143
27	J426 Facility Study			34,585	143
28	J330 Facility Study	498	561.7	19,129	143
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

**Schedule Page: 231 Line No.: 2 Column: b**

The values reported on this page represent the actual costs incurred or reimbursements received in the reporting period. As a result, cost and reimbursements for each study may be reported in different reporting periods.

**OTHER REGULATORY ASSETS (Account 182.3)**

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

Line No.	Description and Purpose of Other Regulatory Assets  (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Conservation and Energy Management Program Costs	9,148,288	144,216,673	Various	133,963,320	19,401,641
2	Minnesota Electric					
3	- MN Docket E-002/M-16-282					
4	- Generally amortized over 12 month					
5	period following the expenditure					
6						
7	Conservation and Energy Management Program Costs	481,231	19,493,673	Various	18,310,899	1,664,005
8	Minnesota Natural Gas					
9	- MN Docket G-002/M-16-283					
10	- Generally amortized over 12 month					
11	period following the expenditure					
12						
13	Conservation and Energy Management Program Costs	42,122		908	42,122	
14	North Dakota Electric					
15	- ND Docket PU-12-813					
16	- Amortized over 4 years (01/2013-12/2016)					
17						
18	Conservation and Energy Management Program Costs	38,053	1,046,160	Various	946,476	137,737
19	South Dakota Electric					
20	- SD Docket EL-15-015					
21	- Generally amortized over 12 month					
22	period following the expenditure					
23						
24	Net of Tax AFUDC in Plant Adjustments	204,088,610	2,640,297			206,728,907
25						
26	South Dakota Ratemaking Differences	3,816,250	188,000	419.1	382,000	3,622,250
27	- SD Docket F-3382					
28	- SD Docket F-3422					
29						
30	Renewable Development Fund Rider	48,918,544	25,600,000	407.3	28,210,993	46,307,551
31	- MN Docket E-002/M-15-730					
32						
33	Asset Retirement Recovery	1,851,863,711	164,690,966			2,016,554,677
34						
35	Minnesota Gas State Energy Policy Rider		841,059	254	841,059	
36	- MN Docket G-002/M-16-206					
37						
38	Minnesota Transmission Cost Recovery Rider	7,967,667	3,344,222	407.3	11,013,382	298,507
39	- MN Docket E-002/M-13-868					
40	- MN Docket E-002/M-15-891					
41						
42	Power Contract Valuation Adjustment	134,103,271		244	16,623,492	117,479,779
43						
44	<b>TOTAL</b>	<b>3,058,047,442</b>	<b>605,198,933</b>		<b>365,385,842</b>	<b>3,297,860,533</b>

**OTHER REGULATORY ASSETS (Account 182.3)**

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

Line No.	Description and Purpose of Other Regulatory Assets  (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Costs to Relocate Facilities Underground	238,928	318,900	142	245,476	312,352
2	- MN Docket E-002/M-13-868					
3						
4	Private Fuel Storage	170,255		407.3	109,819	60,436
5	- Amortized over 4-6 years					
6	- ND Docket PU-12-813 (Amortized 01/2013-12/2016)					
7	- SD Docket EL14-058 (Amortized 01/2010-01/2018)					
8						
9	Deferred Electric Commodity Costs	354,325	3,529,219	456	3,883,544	
10						
11	Mankato/Cannon Falls Lease Normalization	41,536,018	758,114	253	490,118	41,804,014
12						
13	Minnesota Renewable Energy Standard Rider	1,567,846	3,236,115	557	3,524,776	1,279,185
14	- MN Docket E-002/M-14-733					
15	- MN Docket E-002/GR-13-868					
16	- MN Docket E-002/M-15-805					
17						
18	Deferred Nuclear Outage Costs	96,457,704	38,467,616	Various	69,978,843	64,946,477
19	- Generally amortized over 23-24 months					
20	- MN Docket E-002/M-07-1489					
21	- ND Docket PU-07-774					
22	- SD Docket EL-07-035					
23						
24	Benefit Cost Recovery Deficit	378,579,644	88,671,852	184	34,024,133	433,227,363
25						
26	Unrealized Gains on Decommissioning Trust		28,733,464	282	28,733,464	
27	Investments					
28						
29	South Dakota Transmission Cost Recovery Rider	97,047	964,219			1,061,266
30	-SD Docket EL-15-030					
31						
32	Transmission Formula Rates	9,133,076	10,352,618	Various	5,264,213	14,221,481
33						
34	Windsorce Tracker	212,904	233,497	456	446,401	
35	- MN Docket E-002/M-01-1479					
36	- MN Docket E-002/GR-13-868					
37						
38	South Dakota Infrastructure Rider		89,910	254	89,910	
39	-SD Docket EL-15-038					
40						
41	Sherco 3 Depreciation Deferral	9,596,431		407.3	439,537	9,156,894
42	-MN Docket E-002/GR-13-868					
43	- Amortized over 21 years (01/2014-12/2035)					
44	<b>TOTAL</b>	<b>3,058,047,442</b>	<b>605,198,933</b>		<b>365,385,842</b>	<b>3,297,860,533</b>

**OTHER REGULATORY ASSETS (Account 182.3)**

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

Line No.	Description and Purpose of Other Regulatory Assets  (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Theoretical Depreciation Reserve Surplus	237,419,630	50,493,485			287,913,115
2	-MN Docket E-002/GR-12-961					
3	-MN Docket E-002/GR-13-868					
4						
5	North Dakota Transmission Cost Recovery Rider	717,709	140,817			858,526
6	- ND Docket PU-16-658					
7						
8	Gas Utility Infrastructure Cost Rider	16,909,615	3,794,505	Various	4,554,083	16,150,037
9	- MN Docket G-002/M-15-808					
10	- Amortized over 5 years (01/2015-12/2019)					
11						
12	North Dakota Renewable Energy Rider	225,175	353,061	407.3	578,236	
13	- ND Docket PU-15-683					
14						
15	Minnesota Electric Vehicle Tariff	23,418	57,150			80,568
16	- MN Docket E-002/M-15-826					
17						
18	North Dakota Environmental Cleanup	4,141,258	10,452,507			14,593,765
19	- ND Docket PU-15-514					
20						
21	South Dakota Property Tax Collected in the	198,712	709,622	408.1	908,334	
22	Fuel Clause Adjustment					
23	- SD Docket EL 14-058					
24						
25	Minnesota Revenue Decoupling		1,781,212	407.3	1,781,212	
26	- MN Docket E-002/GR-13-868					
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	<b>TOTAL</b>	<b>3,058,047,442</b>	<b>605,198,933</b>		<b>365,385,842</b>	<b>3,297,860,533</b>

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 04/10/2017	2016/Q4
FOOTNOTE DATA			

**Schedule Page: 232 Line No.: 1 Column: d**

Accounts charged:	
456	\$48,546,904
908	85,416,416
Total	<u>\$133,963,320</u>

**Schedule Page: 232 Line No.: 7 Column: d**

Accounts charged:	
431	\$12,101
495	6,897,023
908	11,401,775
Total	<u>\$18,310,899</u>

**Schedule Page: 232 Line No.: 18 Column: d**

Accounts charged:	
431	\$80
908	946,396
Total	<u>\$946,476</u>

**Schedule Page: 232.1 Line No.: 18 Column: c**

Accounts charged:	
517	\$3,339,763
519	944,890
520	4,018,071
523	84,547
524	2,132,145
528	35,286
529	27,898
530	12,131,903
531	3,201,947
532	12,551,166
Total	<u>\$38,467,616</u>

**Schedule Page: 232.1 Line No.: 18 Column: d**

Accounts charged:	
517	\$6,267,577
519	1,045,610
520	8,041,083
523	370,366
524	3,232,119
528	2,706,463
529	73,863
530	23,335,823
531	7,395,828
532	17,510,111
Total	<u>\$69,978,843</u>

**Schedule Page: 232.1 Line No.: 32 Column: d**

Accounts charged:	
456.1	\$4,046,882
565	1,217,331
Total	<u>\$5,264,213</u>

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

**Schedule Page: 232.2 Line No.: 1 Column: c**

<u>Functional Class</u>	<u>December 31, 2015</u>	<u>Amortizations</u>	<u>December 31, 2016</u>
Common General	(\$2,465,544)	(\$522,994)	(\$2,988,538)
Common Intangible	(986,138)	0	(986,138)
Electric Distribution	90,223,941	19,138,412	109,362,353
Electric General	4,858,191	1,030,525	5,888,716
Electric Intangible	365,054	0	365,054
Electric Transmission	123,417,853	26,179,545	149,597,398
Total - MN	<u>\$215,413,357</u>	<u>\$45,825,488</u>	<u>\$261,238,845</u>

<u>Functional Class</u>	<u>December 31, 2015</u>	<u>Amortizations</u>	<u>December 31, 2016</u>
Electric Distribution	\$14,893	\$3,158	\$18,051
Electric General	8,991	1,907	10,898
Electric Transmission	21,982,389	4,662,932	26,645,321
Total - WI	<u>\$22,006,273</u>	<u>\$4,667,997</u>	<u>\$26,674,270</u>

Grand Total	<u>\$237,419,630</u>	<u>\$50,493,485</u>	<u>\$287,913,115</u>
-------------	----------------------	---------------------	----------------------

**Schedule Page: 232.2 Line No.: 8 Column: d**

Accounts charged:	
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	<u>\$4,554,083</u>

**MISCELLANEOUS DEFFERED DEBITS (Account 186)**

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	IPP Power Contract Billing	874,598	25,194	555	50,452	849,340
2	Adjustments					
3						
4	Conservation and Energy	42,170,908	47,629,590	182.3	43,277,219	46,523,279
5	Management Program Costs					
6	Minnesota Electric Incentive					
7	(Docket E-002/M-16-282)					
8						
9	Conservation and Energy	5,545,666	6,117,641	182.3	5,763,443	5,899,864
10	Management Program Costs					
11	Minnesota Gas Incentive					
12	(Docket G-002/M-16-283)					
13						
14	Federal and State Income		3,768,597	409.1	1,947,492	1,821,105
15	Taxes Receivable					
16						
17	Federal and State Income	3,048,219	680,104			3,728,323
18	Tax Interest Receivable					
19						
20	Debt Issuance Costs	700	2,643,804	181	2,372,003	272,501
21						
22	2016 Minnesota Electric Retail	1,386,934	3,269,845	928	2,430,112	2,226,667
23	Rate Case					
24	- Amortized through Dec. 2018					
25	(Docket E-002/GR-15-826)					
26						
27	2010 North Dakota Electric	53,105		928	53,105	
28	Retail Rate Case					
29	- Amortized through Dec. 2016					
30	(Docket PU-10-657)					
31	(Docket PU-12-813)					
32						
33	2013 North Dakota Electric	154,500		928	154,500	
34	Retail Rate Case					
35	-Amortized through Dec. 2016					
36	(Docket PU-12-813)					
37						
38	North Dakota Electric	502,126	363,458			865,584
39	Retail Rate Case - Settlement					
40	(Docket PU-12-813)					
41						
42	2014 South Dakota Electric	238,386		928	119,193	119,193
43	Retail Rate Case					
44	- Amortized through Dec. 2017					
45	(Docket EL14-058)					
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	<b>TOTAL</b>	<b>54,088,311</b>				<b>62,619,320</b>

Name of Respondent  
Northern States Power Company (Minnesota)

This Report Is:  
(1)  An Original  
(2)  A Resubmission

Date of Report  
(Mo, Da, Yr)  
04/10/2017

Year/Period of Report  
End of 2016/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	Future South Dakota Electric	113,169				113,169
2	Retail Rate Case					
3	(Docket EL 14-058)					
4						
5	Notes Receivable - 3rd Party		200,295			200,295
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	54,088,311				62,619,320

**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 Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Electric - Plant	298,903,603	306,154,752
3	Electric - Non-Plant	609,866,965	634,722,776
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	908,770,568	940,877,528
9	Gas		
10		36,048,546	39,870,049
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)	36,048,546	39,870,049
17	Other (Specify)	55,800,640	57,020,275
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	1,000,619,754	1,037,767,852

Notes

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

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

	Balance at Beginning of Year	Balance at End of Year
Electric Plant Related Only:		
Electric Distribution Plant	\$76,048,313	\$88,139,293
Electric General Plant	447,563	333,318
Electric Intangible Plant	6,114,820	5,824,660
Electric Nuclear Fuel	23,492,096	24,599,341
Electric Nuclear Production Plant	89,454,340	84,738,674
Electric Production Plant	45,505,619	45,376,009
Electric Transmission Plant	39,159,422	39,849,355
Electric Transmission - Production Plant	573,614	578,380
Common (Allocation to Electric)	628,168	610,759
Regulatory Difference - Effect of Rate Changes	(539,634)	(816,642)
Regulatory Difference - Investment Tax Credit Gross-Up	18,019,282	16,921,605
Total Electric Plant Related Only	<u>\$298,903,603</u>	<u>\$306,154,752</u>

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

	Balance at Beginning of Year	Balance at End of Year
Electric:		
Avoided Tax Interest	\$140,545,071	\$140,266,767
Bad Debts	7,692,393	7,559,768
Customer Advances	389,493	332,802
Deferred Connection Fees	67,748,255	79,759,526
Deferred Rent	0	4,457,496
Deferred Revenue	1,239,715	1,214,749
Economic Development Securities - Write-Off	227,629	227,470
Electric Vehicle Credit	6,944	6,944
Employee Incentive Plans	6,927,682	7,045,573
Employee Retention	4,316	0
Employee Stock Ownership Program Dividends	5,983,639	6,295,359
End of Life Nuclear Fuel Amortization	23,492,096	24,599,341
Environmental Remediation	77,516	91,732
Federal Net Operating Loss	346,606,795	304,695,697
Fuel Tax Credit - Income Addback	23,324	16,548
Inventory Reserve	231,778	893,862
Investment Tax Credit	2,523,322	1,737,177
Investment Tax Credit Grant	1,119,598	1,239,514
Litigation Reserve	30,028	182,107
Medical Deductions - Self Insured	837,727	841,145
Monticello Extended Power Uprate Writedown	43,265,401	38,795,994
New Hire Retention Credit	52,102	52,102
North Dakota Investment Tax Credit	28,475,301	64,345,539
North Dakota Investment Tax Credit - Valuation Allowance	(24,784,085)	(59,421,769)
North Dakota Investment Tax Credit - Federal Gross-Up	1,987,578	2,651,261
Performance Recognition Awards	13,145	38,047
Post Employment Benefits - Retiree Medical	25,173,957	22,584,681
Post Employment Benefits - Long Term Disability	7,067,199	6,292,255
Purchased Power Capacity	82,616	82,558
Rate Refund	26,297,851	21,093,779
Regulatory Asset/Liability - Prairie Island Extended Power Uprate Cancellation	2,072,561	1,835,785

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Regulatory Asset/Liability - Windsources	0	95,196
Regulatory Difference - Effect of Rate Changes	(539,634)	(816,642)
Regulatory Difference - Investment Tax Credit Gross-Up	18,019,282	16,921,605
Research and Experimentation Credit	41,059,275	44,940,397
Sale of Emission Allowances	11,418	43,566
Severance Accrual	80,314	74,421
Solar Rewards Program	0	8,068,952
South Dakota Infrastructure Tracker	238,621	201,799
State Research Credit	3,518,999	4,082,247
State Research Credit - Valuation Allowance	(110,751)	(949,735)
State Tax Deduction Cash vs. Accrual	1,013,004	695,519
Vacation Accrual	7,388,006	7,439,978
Wind Production Tax Credit	122,640,676	180,228,683
Workers Compensation	40,411	37,733
Total Electric	\$908,770,568	\$940,877,528

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 in the formula. An adjustment is made to eliminate the accumulated deferred income tax balances related to postretirement employee benefits and regulatory differences related to income taxes.

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

	Balance at Beginning of Year	Balance at End of Year
Gas:		
Avoided Tax Interest	\$2,445,068	\$2,565,968
Bad Debts	773,354	580,954
Deferred Connection Fees	9,557,232	10,029,621
Deferred Rent	0	375,002
Deferred Revenue	57,117	100,905
Economic Development Securities - Write-Off	22,885	22,869
Electric Vehicle Credit	556	556
Employee Incentive Plans	518,236	601,852
Employee Retention	323	0
Employee Stock Ownership Program Dividends	1,908,845	1,989,928
Environmental Remediation	1,207,136	4,699,435
Federal Net Operating Loss	14,427,885	13,840,632
Fuel Tax Credit - Income Addback	1,867	1,324
Inventory Reserve	18,549	75,199
Litigation Reserve	3,019	13,995
Lower of Cost or Market on Gas Inventories	179,538	168,070
Medical Deduction - Self Insured	62,667	83,910
New Hire Retention Credit	3,898	3,898
Performance Recognition Awards	983	3,250
Post Employment Benefits - Retiree Medical	1,883,176	1,929,246
Post Employment Benefits - Long Term Disability	528,673	537,502
Regulatory Difference - Effect of Rate Changes	535,625	488,429
Regulatory Difference - Investment Tax Credit Gross-Up	1,269,737	1,080,848
Severance Accrual	6,008	6,357
State Tax Deduction Cash vs. Accrual	80,475	31,533
Vacation Accrual	552,671	635,543
Workers' Compensation	3,023	3,223
Total Gas	\$36,048,546	\$39,870,049

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

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

Other:	Balance at Beginning of Year	Balance at End of Year
Avoided Tax Interest	(\$404)	(\$207)
Contributions Carryover	5,897,814	5,534,921
Deferred Compensation Plan Reserve	4,977,582	5,143,407
Federal Net Operating Loss	8,220,880	10,378,683
Fuel Hedging	783	0
Low Income Housing Credit	3,344,790	3,344,790
Minnesota Net Operating Loss	15,225,655	14,707,436
North Dakota Net Operating Loss	1,068,286	957,530
Nonqualified Pension Plans	1,102,029	967,496
Other Comprehensive Income	14,600,975	14,378,872
Partnership Passthrough	544,090	473,559
Performance Share Plan	796,647	1,108,669
Regulatory Difference - Effect of Rate Changes	(16)	(16)
State Tax Deduction Cash vs. Accrual	21,529	25,135
Total Other	<u>\$55,800,640</u>	<u>\$57,020,275</u>

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	
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

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
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42

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	2,955,813,212
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40	TOTAL	2,955,813,212

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

**Schedule Page: 253 Line No.: 2 Column: b**

In 2016 an adjustment was recorded to move the life to date contributions of capital from FERC Account No. 207, Premium on Capital Stock, to FERC Account No. 211, Miscellaneous Paid-In Capital.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report End of <u>2016/Q4</u>
---	---	--	--

CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	

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	5.25% March 1, 2018 First Mortgage Bonds	500,000,000	4,815,362
5			1,520,000 D
6			
7	2.15% Aug. 15, 2022 First Mortgage Bonds	300,000,000	3,088,686
8			456,000 D
9			
10	7.125% July 1, 2025 First Mortgage Bonds	250,000,000	1,898,288
11			2,330,000 D
12			
13	6.50% March 1, 2028 First Mortgage Bonds	150,000,000	1,474,427
14			1,761,001 D
15			
16	5.25% July 15, 2035 First Mortgage Bonds	250,000,000	3,032,114
17			485,000 D
18			
19	6.25% June 1, 2036 First Mortgage Bonds	400,000,000	4,877,065
20			1,404,000 D
21			
22	6.20% July 1, 2037 First Mortgage Bonds	350,000,000	4,336,843
23			1,988,000 D
24			
25	5.35% Nov. 1, 2039 First Mortgage Bonds	300,000,000	4,153,918
26			570,000 D
27			
28	4.85% Aug. 15, 2040 First Mortgage Bonds	250,000,000	3,019,146
29			707,500 D
30			
31	3.40% Aug 15, 2042 First Mortgage Bonds	500,000,000	6,272,718
32			3,820,000 D
33	TOTAL	4,900,000,000	81,880,387

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			
2	2.60% May 15, 2023 First Mortgage Bonds	400,000,000	4,524,626
3			732,000 D
4			
5	4.125% May 15, 2044 First Mortgage Bonds	300,000,000	3,821,358
6			873,000 D
7			
8	2.20% Aug. 15, 2020 First Mortgage Bonds	300,000,000	3,072,956
9			552,000 D
10			
11	4.00% Aug. 15, 2045 First Mortgage Bonds	300,000,000	3,897,956
12			4,899,000 D
13			
14	3.60% May 15, 2046 First Mortgage Bonds	350,000,000	5,404,423
15			2,093,000 D
16	SUBTOTAL - ACCOUNT 221	4,900,000,000	81,880,387
17			
18	ACCOUNT 224		
19	OTHER LONG TERM DEBT		
20			
21	Right of Way debt		
22			
23	SUBTOTAL - ACCOUNT 224		
24			
25	Interest on Debt to Associated Companies		
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	4,900,000,000	81,880,387

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		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
						2
						3
3/18/2008	3/1/2018	3/18/2008	3/1/2018	500,000,000	26,769,554	4
						5
						6
8/13/2012	8/15/2022	8/13/2012	8/15/2022	300,000,000	6,450,000	7
						8
						9
7/1/1995	7/1/2025	7/1/1995	7/1/2025	250,000,000	17,812,500	10
						11
						12
3/1/1998	3/1/2028	3/1/1998	3/1/2028	150,000,000	9,750,000	13
						14
						15
7/21/2005	7/15/2035	7/21/2005	7/15/2035	250,000,000	13,125,000	16
						17
						18
5/25/2006	6/1/2036	5/25/2006	6/1/2036	400,000,000	24,453,968	19
						20
						21
6/26/2007	7/1/2037	6/26/2007	7/1/2037	350,000,000	21,510,341	22
						23
						24
11/17/2009	11/1/2039	11/17/2009	11/1/2039	300,000,000	16,157,285	25
						26
						27
8/11/2010	8/15/2040	8/11/2010	8/15/2040	250,000,000	12,125,000	28
						29
						30
8/13/2012	8/15/2042	8/13/2012	8/15/2042	500,000,000	18,500,579	31
						32
				4,900,022,518	215,729,453	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		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
5/20/2013	5/15/2023	5/20/2013	5/15/2023	400,000,000	10,400,000	2
						3
						4
5/13/2014	5/15/2044	5/13/2014	5/15/2044	300,000,000	12,375,000	5
						6
						7
8/11/2015	8/15/2020	8/11/2015	8/15/2020	300,000,000	6,600,000	8
						9
						10
8/11/2015	8/15/2045	8/11/2015	8/15/2045	300,000,000	12,000,000	11
						12
						13
5/31/2016	5/15/2046	5/31/2016	5/15/2046	350,000,000	7,385,000	14
						15
				4,900,000,000	215,414,227	16
						17
						18
						19
						20
				22,518		21
						22
				22,518		23
						24
					315,226	25
						26
						27
						28
						29
						30
						31
						32
				4,900,022,518	215,729,453	33

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

**Schedule Page: 256 Line No.: 4 Column: i**

Interest at stated rate	\$26,250,000
Interest swap loss	519,554
	<u>\$26,769,554</u>

**Schedule Page: 256 Line No.: 19 Column: i**

Interest at stated rate	\$25,000,000
Interest swap gain	(546,032)
	<u>\$24,453,968</u>

**Schedule Page: 256 Line No.: 22 Column: i**

Interest at stated rate	\$21,700,000
Interest swap gain	(189,659)
	<u>\$21,510,341</u>

**Schedule Page: 256 Line No.: 25 Column: i**

Interest at stated rate	\$16,050,000
Interest swap loss	107,285
	<u>\$16,157,285</u>

**Schedule Page: 256 Line No.: 31 Column: i**

Interest at stated rate	\$17,000,000
Interest swap loss	1,500,579
	<u>\$18,500,579</u>

**Schedule Page: 256.1 Line No.: 14 Column: a**

Minnesota Public Utilities Commission docket E,G002/S-15-948. Order dated Apr. 8, 2016.

NSP-Minnesota issued \$350 million of 3.60 percent First Mortgage Bonds due May 15, 2046. NSP-Minnesota used a portion of the net proceeds from the sale to repay short-term borrowings and for other general corporate purposes.

**Schedule Page: 256.1 Line No.: 21 Column: h**

	Balance Dec. 31, 2015	Additions	Reductions	Balance Dec. 31, 2016
Right of Way debt	\$ 33,400	\$	\$ (10,882)	\$ 22,518

**Schedule Page: 256.1 Line No.: 25 Column: i**

Xcel Energy Services Inc	\$134,647
NSP Nuclear Corp	9,497
Money Pool	171,082
	<u>\$315,226</u>

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

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.

2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.

3. A substitute page, designed to meet a particular need of a company, may be used as long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	488,743,682
2		
3		
4	Taxable Income Not Reported on Books	
5		28,064,959
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		860,897,526
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		-31,129,293
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		-1,501,824,891
21		
22	Equity in Earnings of Subsidiary Companies	79,953
23		
24	Total Income Tax Expense	224,574,940
25		
26		
27	Federal Tax Net Income	69,406,876
28	Show Computation of Tax:	
29	Federal Income Tax at 35 percent	24,292,407
30	Other	-3,831,711
31	Total Federal Income Tax Payable	20,460,696
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)		04/10/2017	2016/Q4
FOOTNOTE DATA			

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

TAXABLE INCOME NOT REPORTED ON BOOKS:  
Contributions in Aid of Construction

\$28,064,959  
\$28,064,959

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

DEDUCTIONS RECORDED ON BOOKS NOT DEDUCTED FOR RETURN:

Avoided Cost Interest	\$17,600,923
Book Amortization - Computer Software	43,433,609
Book Amortization - Other	12,749,204
Book Depreciation	492,860,703
Book Income - Wisconsin/South Dakota Allowance for Funds During Construction	194,000
Book Unamortized Cost of Reacquired Debt	1,933,092
Capitalization of Software Expense - Books	733,698
Clearing Account Book Expense	17,671,324
Contributions Carryover	4,075,497
Deferred Compensation Plan Reserve	415,235
Deferred Rent	11,853,189
Deferred Revenue	48,380
Employee Incentive Plans	506,972
Employee Stock Ownership Plan Dividends	1,746,051
Environmental Remediation	8,603,000
Interest Income/Expense on Disputed Tax	2,359,243
Inventory Reserve	1,763,344
Litigation Reserve	400,000
Lobbying Expenses	1,508,000
Meals & Entertainment	1,069,000
Medical Deduction - Self Insured	376,496
Nuclear Decommissioning	20,371,744
Nuclear Fuel Expense	116,958,768
Penalties	76,271
Pension Expense	28,862,064
Performance Recognition Awards	66,663
Performance Share Plan	766,691
Prairie Island Extended Power Uprate Writedown Amortization	2,888,815
Regulatory Asset - Gas Safety Deferrals	759,578
Regulatory Asset - Nuclear Refueling Outage Costs	31,511,227
Regulatory Asset - Property Tax	198,712
Regulatory Asset/Liability - Renewable Energy Standard (RES) Rider	288,660
Regulatory Asset/Liability - Transmission Cost Recovery Rider	5,815,389
Regulatory Asset/Liability - Windsource	446,401
Renewable Energy Standard/Credit	2,561
Sale of Emission Allowances	78,874
Solar Rewards Program	19,791,589
Suite and Entertainment Tickets	149,000
Unbilled Revenue - Fuel Costs	9,619,253
Vacation Accrual	344,306
	<u>\$860,897,526</u>

**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) (\$30,952,507)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)		04/10/2017	2016/Q4

FOOTNOTE DATA

Deferred Revenue - Investment Tax Credit (ITC) Grant	(176,786)
	<u>(\$31,129,293)</u>

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

**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)	(\$14,472,310)
Bad Debts	(782,771)
Deferred Fuel Costs	(12,167,049)
Electric Vehicle Charging Tariff	(57,149)
Employee Retention	(36,082)
External Qualified Nuclear Decommissioning Fund	(20,371,744)
Federal Net Operating Loss	(97,183,506)
Fuel Hedging	(1,918)
Gain/(Loss) on Dispositions (Tax)	(2,899,613)
Internally Developed Software	(2,001,456)
Insurance Fund Income (Cash Value)	(3,030,447)
Interest Expense - Capital Leases	(110,576)
Mark to Market Adjustment	(2,825,231)
Nonqualified Pension Plan	(328,100)
Partnership Passthrough	(21,800)
Pension and Benefit Capitalized	(6,508,945)
Post Employment Benefits - Retiree Medical	(6,191,798)
Post Employment Benefits - Long Term Disability	(1,866,162)
Prepaid Advertising	(1)
Prepaid Insurance	(5,558,594)
PUCIP Adjustment	(16,200,258)
Rate Case/Restructuring Expense	(876,393)
Rate Refund	(12,719,689)
Regulatory Asset - Prairie Island Extended Power Uprate Cancellation	(577,228)
Regulatory Asset/Liability - Transmission Attach O	(388,164)
Regulatory Reserve - Environmental	(10,452,506)
Repair Expenditures	(91,428,721)
Section 174	(41,997,619)
Severance Accrual	(13,451)
South Dakota Infrastructure Tracker	(89,910)
State Tax Deduction	(5,914,762)
Tax Amortization - Monticello Rerate	(6,295,644)
Tax Amortization - Computer Software	(30,434,211)
Tax Amortization - Pollution Control Facilities	(589,665)
Tax Depreciation	(1,035,452,604)
Tax Expense - Ash Ponds and Landfills	(238,559)
Tax Expense - Spent Fuel Isolation Devices	(17,593,872)
Tax Removal Cost Over Book	(54,140,381)
Workers' Compensation	(6,002)
	<u>(\$1,501,824,891)</u>

**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 2016. The other members of the affiliated group and the federal income tax provision of each are:

Xcel Energy Inc.	(\$58,101,251)
------------------	----------------

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)		04/10/2017	2016/Q4
FOOTNOTE DATA			

NSP Nuclear Corporation	8,570
United Power and Land Company	(46,815)
Northern States Power Company (Wisconsin) and Subsidiaries	5,416,012
Public Service Company of Colorado and Subsidiaries	45,678,905
Southwestern Public Service Company	(40,400,089)
Nicollet Holdings Company, LLC and Subsidiaries	(30,161)
Xcel Energy Communications Group Inc. and Subsidiaries	182,695
Xcel Energy Markets Holdings Inc. and Subsidiaries	337,970
Xcel Energy International Inc.	(1,799)
Xcel Energy Retail Holdings Inc. and Subsidiaries	(85,878)
Xcel Energy Transmission Holding Company, LLC and Subsidiaries	(569,061)
Xcel Energy Ventures Inc. and Subsidiaries	(284,623)
Xcel Energy Venture Holdings, Inc. and Subsidiaries	(458,504)
Xcel Energy Wholesale Group Inc. and Subsidiaries	792,003
Xcel Energy WYCO Inc.	12,294,526
WestGas Interstate, Inc.	46,352
Xcel Energy Services Inc.	13,967,615

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.

**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 known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (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 Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	FEDERAL TAXES					
2	Income		21,015,225	19,338,413	33,098,295	17,659,301
3	Income Tax Adjustment			1,122,283		-1,122,283
4						
5	FICA 2015	2,070,573			2,070,573	
6	FICA 2016			35,952,156	33,773,048	
7						
8	Unemployment 2015	4,278			4,278	
9	Unemployment 2016			210,347	207,655	
10						
11	Heavy Vehicle Use Tax					
12						
13	SUBTOTAL	2,074,851	21,015,225	56,623,199	69,153,849	16,537,018
14						
15	STATE TAXES					
16	MINNESOTA					
17	Income		12,741,501	9,338,560	5,858,919	911,364
18	Income Tax Adjustment			233,291		-233,291
19						
20	Unemployment 2015	97,796			97,796	
21	Unemployment 2016			3,802,322	3,728,983	
22						
23	Real Estate 2015	102,500,000		265,273	-102,765,273	
24	Real Estate 2016			110,470,000		
25	Real Estate directly ex					
26						
27	Personal Property 2015	90,000,000		-779,891	-89,220,109	
28	Personal Property 2016			93,930,000		
29	Personal Property directly ex					
30						
31	Use 2015	1,381,422		-223,261	-1,158,161	
32	Use 2016			9,706,823	-5,913,597	
33						
34	SUBTOTAL	193,979,218	12,741,501	226,743,117	-189,371,442	678,073
35						
36	STATE TAXES					
37	NORTH DAKOTA					
38	Income	103,100		55,281	4,504	16,061
39	Income Tax Adjustment			426		-426
40						
41	TOTAL	203,255,169	33,768,596	294,403,653	-126,004,616	17,162,684

**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 known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (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 Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	Unemployment 2015	1,071			1,071	
2	Unemployment 2016			12,459	12,264	
3						
4	Personal Property 2015	3,200,000		15,401	-3,215,401	
5	Personal Property 2016			4,650,000		
6						
7	Use 2015		11,858	15,615	-3,757	
8	Use 2016			30,555	-20,550	
9						
10	<b>SUBTOTAL</b>	<b>3,304,171</b>	<b>11,858</b>	<b>4,779,737</b>	<b>-3,221,869</b>	<b>15,635</b>
11						
12	<b>STATE TAXES</b>					
13	<b>SOUTH DAKOTA</b>					
14	Unemployment 2015	105			105	
15	Unemployment 2016			17,909	24,931	
16						
17	Personal Property 2015	3,700,000		-56,562	-3,643,438	
18	Personal Property 2016			3,800,000		
19	Personal Property FCA			801,500	801,500	
20						
21	Use 2015	31,739		-18,152	-13,587	
22	Use 2016			271,385	-272,494	
23						
24	<b>SUBTOTAL</b>	<b>3,731,844</b>		<b>4,816,080</b>	<b>-3,102,983</b>	
25						
26	<b>STATE TAXES</b>					
27	<b>KANSAS</b>					
28	Personal Property 2015					
29	Personal Property 2016			524,637	-524,637	
30						
31	<b>SUBTOTAL</b>			<b>524,637</b>	<b>-524,637</b>	
32						
33	<b>STATE TAXES</b>					
34	<b>WISCONSIN</b>					
35	Income	123,000		-86,619	51,339	-68,042
36						
37	Unemployment 2016			7,173	7,486	
38						
39	<b>SUBTOTAL</b>	<b>123,000</b>		<b>-79,446</b>	<b>58,825</b>	<b>-68,042</b>
40						
41	<b>TOTAL</b>	<b>203,255,169</b>	<b>33,768,596</b>	<b>294,403,653</b>	<b>-126,004,616</b>	<b>17,162,684</b>

**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 Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	OTHER					
2	Colorado Unemployment			113	113	
3	Denver Occ'l Priviledge		12	44	36	
4	Property Tax on Rail Car	42,085		-37,484	-4,601	
5	Property Tax on Rail Car			20,000	-5,563	
6	Other			1,013,656	1,013,656	
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	203,255,169	33,768,596	294,403,653	-126,004,616	17,162,684

**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 (i) 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
	17,115,806	23,481,209			-4,142,796	2
		1,077,465			44,818	3
						4
						5
2,179,108		26,916,270			9,035,886	6
						7
						8
2,692		160,288			50,059	9
						10
						11
						12
2,181,800	17,115,806	51,635,232			4,987,967	13
						14
						15
						16
	8,350,496	11,105,593			-1,767,033	17
		222,520			10,771	18
						19
						20
73,339		2,209,546			1,592,776	21
						22
		260,700			4,573	23
110,470,000		108,670,000			1,800,000	24
						25
						26
		-647,610			-132,281	27
93,930,000		78,285,000			15,645,000	28
						29
						30
					-223,261	31
3,793,225					9,706,823	32
						33
208,266,564	8,350,496	200,105,749			26,637,368	34
						35
						36
						37
169,938		247,737			-192,456	38
		140			286	39
						40
						41
219,084,491	25,549,302	261,255,892			33,147,761	41

**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
195		6,833			5,626	2
						3
		166,395			-150,994	4
4,650,000		3,675,000			975,000	5
						6
					15,615	7
10,005					30,555	8
						9
4,830,138		4,096,105			683,632	10
						11
						12
						13
						14
-7,022		9,822			8,087	15
						16
		-56,562				17
3,800,000		3,800,000				18
		801,500				19
						20
					-18,152	21
-1,109					271,385	22
						23
3,791,869		4,554,760			261,320	24
						25
						26
						27
						28
					524,637	29
						30
					524,637	31
						32
						33
						34
	83,000	-86,619				35
						36
-313		3,934			3,239	37
						38
-313	83,000	-82,685			3,239	39
						40
						41
219,084,491	25,549,302	261,255,892			33,147,761	41

**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 (i) 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
		62			51	2
-4		11,617			-11,573	3
					-37,484	4
14,437					20,000	5
		935,052			78,604	6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
219,084,491	25,549,302	261,255,892			33,147,761	41

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
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)	\$ 956,721
Federal income tax expense (409.1 and 409.2) accrued for long term income tax payable (253)	731,725
Annual allocation of unitary benefit/detriment for state income taxes accrued as additional paid in capital (211)	23,815
Federal tax benefit (accrual and cash) for net operating loss carryback accrued in other accounts receivable (143)	15,947,041
Rounding	(1)
	<u>\$ 17,659,301</u>

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

Gas (Account No. 409.1)	\$ (4,210,418)
Other income and deductions (Account No. 409.2)	67,622
	<u>\$ (4,142,796)</u>

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

Federal income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)	\$ 11,220
Federal income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)	(1,133,503)
	<u>\$ (1,122,283)</u>

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

Gas (Account No. 409.1)	\$ 3,017
Other income and deductions (Account No. 409.2)	41,801
	<u>\$ 44,818</u>

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

Gas (Account No. 408.1)	\$ 2,337,475
Other	6,698,411
	<u>\$ 9,035,886</u>

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

Gas (Account No. 408.1)	\$ 13,909
Other	36,150
	<u>\$ 50,059</u>

**Schedule Page: 262 Line No.: 17 Column: f**

State income tax expense (409.1 and 409.2) accrued for long term income tax receivable (186)	\$ 850,891
State income tax expense (409.1 and 409.2) accrued for long term income tax payable (253)	60,472
Rounding	1
	<u>\$ 911,364</u>

**Schedule Page: 262 Line No.: 17 Column: l**

Gas (Account No. 409.1)	\$ (243,871)
Other income and deductions (Account No. 409.2)	(1,523,162)
	<u>\$ (1,767,033)</u>

**Schedule Page: 262 Line No.: 18 Column: f**

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)	\$ 241
State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)	(233,532)
	<u>\$ (233,291)</u>

**Schedule Page: 262 Line No.: 18 Column: I**

Gas (Account No. 409.1)	\$ 742
Other income and deductions (Account No. 409.2)	10,029
	<u>\$ 10,771</u>

**Schedule Page: 262 Line No.: 21 Column: I**

Gas (Account No. 408.1)	\$ 195,494
Other	1,397,282
	<u>\$ 1,592,776</u>

**Schedule Page: 262 Line No.: 23 Column: I**

Gas (Account No. 408.1)	\$ 4,573
-------------------------	----------

**Schedule Page: 262 Line No.: 24 Column: I**

Gas (Account No. 408.1)	\$ 1,740,000
Other income and deductions (Account No. 408.2)	60,000
	<u>\$ 1,800,000</u>

**Schedule Page: 262 Line No.: 27 Column: I**

Gas (Account No. 408.1)	\$ (132,281)
-------------------------	--------------

**Schedule Page: 262 Line No.: 28 Column: I**

Gas (Account No. 408.1)	\$ 15,639,000
Other income and deductions (Account No. 408.2)	6,000
	<u>\$ 15,645,000</u>

**Schedule Page: 262 Line No.: 38 Column: f**

State income tax expense (409.1 and 409.2) accrued for long term income tax receivable (186)	\$ 13,493
State income tax expense (409.1 and 409.2) accrued for long term income tax payable (253)	2,568
	<u>\$ 16,061</u>

**Schedule Page: 262 Line No.: 38 Column: I**

Gas (Account No. 409.1)	\$ (15,998)
Other income and deductions (Account No. 409.2)	(176,458)
	<u>\$ (192,456)</u>

**Schedule Page: 262 Line No.: 39 Column: f**

State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)	\$ (52)
State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)	(374)
	<u>\$ (426)</u>

**Schedule Page: 262 Line No.: 39 Column: I**

Gas (Account No. 409.1)	\$ 16
Other income and deductions (Account No. 409.2)	270
	<u>\$ 286</u>

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

**Schedule Page: 262.1 Line No.: 2 Column: I**

Gas (Account No. 408.1)	\$ 608
Other	5,018
	<u>\$ 5,626</u>

**Schedule Page: 262.1 Line No.: 4 Column: I**

Gas (Account No. 408.1)	\$ (150,994)
-------------------------	--------------

**Schedule Page: 262.1 Line No.: 5 Column: I**

Gas (Account No. 408.1)	\$ 975,000
-------------------------	------------

**Schedule Page: 262.1 Line No.: 15 Column: I**

Gas (Account No. 408.1)	\$ 873
Other	7,214
	<u>\$ 8,087</u>

**Schedule Page: 262.1 Line No.: 19 Column: a**

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

**Schedule Page: 262.1 Line No.: 29 Column: I**

Gas (Account No. 408.1)	\$ 524,637
-------------------------	------------

**Schedule Page: 262.1 Line No.: 35 Column: f**

Annual allocation of unitary benefit/detriment for Wisconsin income tax accrued as additional paid in capital (211)	\$ (68,042)
	<u>\$ (68,042)</u>

**Schedule Page: 262.1 Line No.: 37 Column: I**

Gas (Account No. 408.1)	\$ 350
Other	2,889
	<u>\$ 3,239</u>

**Schedule Page: 262.2 Line No.: 2 Column: I**

Gas (Account No. 408.1)	\$ 6
Other	45
	<u>\$ 51</u>

**Schedule Page: 262.2 Line No.: 3 Column: I**

Gas (Account No. 408.1)	\$ 946
Other	(12,519)
	<u>\$ (11,573)</u>

**Schedule Page: 262.2 Line No.: 4 Column: a**

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

**Schedule Page: 262.2 Line No.: 5 Column: a**

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

**Schedule Page: 262.2 Line No.: 6 Column: I**

Gas (Account No. 408.1)	\$ 78,604
-------------------------	-----------

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

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%	66,626			411.4	5,003	
4	7%						
5	10%	22,051,223			411.4	1,283,317	
6	30%	1,771,079			411.4	97,312	
7							
8	TOTAL	23,888,928				1,385,632	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12	4%	1,744			411.4	65	
13	10%	1,831,703			411.4	271,667	
14	TOTAL	1,833,447				271,732	
15							
16							
17	4%	6,158			411.4	445	
18	10%	109,349			411.4	4,841	
19	TOTAL	115,507				5,286	
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48	Utility & Non-Utili	25,837,882				1,662,650	

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
61,623	56 Years		3
			4
20,767,906	51 Years		5
1,673,767	22 Years		6
			7
22,503,296			8
			9
			10
			11
1,679	68 Years		12
1,560,036	42 Years		13
1,561,715			14
			15
			16
5,713	55 Years		17
104,508	55 Years		18
110,221			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
24,175,232			48

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
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.: 19 Column: h**

(a) Common Allocation

Electric - 92.24%	\$101,672
Gas - 7.76%	\$ 8,549
	\$110,221

**OTHER DEFERRED CREDITS (Account 253)**

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Unfunded Nonqualified Pension	4,775,586	232	1,108,761	1,942,425	5,609,250
2	Benefit Costs					
3						
4	Deferred Compensation					
5	Employees	5,829,662	146	567,914	1,537,791	6,799,539
6	Employees (Wealth Op)	6,370,893	232	740,887	186,245	5,816,251
7						
8	Postemployment Benefit-Injury	18,618,244	232	3,341,177	1,475,015	16,752,082
9	Compensation					
10						
11	Environmental & Regulatory	214,444			3,449,366	3,663,810
12	Reserves					
13						
14	Nuclear Waste Strategy Coalition	78,094	232	76,119	99,267	101,242
15						
16	Renewable Development Fund	44,735,407	232	29,884,407	25,600,000	40,451,000
17	Obligations					
18						
19	Long-Term Income Tax & Interest	10,530,973			976,194	11,507,167
20	Payable					
21						
22	Deposits-Landfill Power	295,737			288	296,025
23						
24	Customer Prepayments	2,239,750	Various	2,093,600	300	146,450
25						
26	Deferred Revenue	774,786	Various	1,674,566	1,610,160	710,380
27						
28	Wholesale Merger Settlement	82,703				82,703
29						
30	Pre-Funded AFUDC					
31	Metro Emissions Reduction Rider	61,282,368	405	2,231,892		59,050,476
32	Mercury Emission Reduction Rider	599,035	405	55,576		543,459
33	Minnesota Transmission Cost	30,473,672	Various	709,423	2,562,014	32,326,263
34	Recovery Rider					
35	FERC Transmission	41,147,790	405	689,758	118,223	40,576,255
36	Renewable Energy Standards Rider	22,194,629	405	1,168,762	7,109,313	28,135,180
37	South Dakota Transmission	1,689,073	Various	40,766	174,423	1,822,730
38	Cost Recovery Rider					
39	North Dakota Transmission	980,557	Various	14,782	208,349	1,174,124
40	Cost Recovery Rider					
41						
42	NMC Long-Term Incentive	1,078,232			866,735	1,944,967
43						
44	Deferred Revenue-ITC Grant	2,152,428	405	162,052		1,990,376
45						
46	Mark-to-Market Adjustment	9,054,900	456	134,727		8,920,173
47	<b>TOTAL</b>	<b>315,499,429</b>		<b>49,757,055</b>	<b>65,554,598</b>	<b>331,296,972</b>

OTHER DEFERRED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Mankato/Cannon Falls Lease	41,536,018	182.3	490,118	758,114	41,804,014
2	Normalization					
3						
4	Long-Term Payroll Tax Liability	1,640,320				1,640,320
5						
6	Coal Car Residual Value Deficit	1,072,003	151	56,421	550,268	1,565,850
7						
8	Nuclear Fuel Services	259,586	517	119,096		140,490
9						
10	Sherco Unit 3 Insurance Settlement	5,755,548	107	360,090		5,395,458
11						
12	401 Nicollet Lease Credit	36,991	Various	4,036,161	16,330,108	12,330,938
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	** Footnote from page 106b					
45						
46						
47	TOTAL	315,499,429		49,757,055	65,554,598	331,296,972

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

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

Accounts charged:	
107	\$1,839,600
232	254,000
Total	\$2,093,600

**Schedule Page: 269 Line No.: 26 Column: c**

Accounts charged:	
447	\$379,280
454	112,786
456	300,000
495	882,500
Total	\$1,674,566

**Schedule Page: 269 Line No.: 33 Column: c**

Accounts charged:	
405	\$709,294
432	129
Total	\$709,423

**Schedule Page: 269 Line No.: 35 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, a total company unjurisdictionalized amortization expense (405) amount is \$965,645

**Schedule Page: 269 Line No.: 35 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, a total company unjurisdictionalized Pre-funded AFUDC (Total Accounts Other Expenses - 432, Other Revenue - 419.1) amount is \$145,116

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

Accounts charged:	
405	\$23,019
419.1	12,066
432	5,681
Total	\$40,766

**Schedule Page: 269 Line No.: 39 Column: c**

Accounts charged:	
405	\$13,841
419.1	644
432	297
Total	\$14,782

**Schedule Page: 269.1 Line No.: 12 Column: c**

Accounts charged:	
232	\$2,790,556
507	1,245,605
Total	\$4,036,161

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

**Schedule Page: 269.1 Line No.: 44 Column: a**

The Form 1 reports that 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.

**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 relating 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)	Amounts Credited to Account 411.1  (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	34,967,609	-2,043,500	
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	34,967,609	-2,043,500	
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)	34,967,609	-2,043,500	
18	Classification of TOTAL			
19	Federal Income Tax	27,213,785	-1,592,613	
20	State Income Tax	7,753,824	-450,887	
21	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
							3
						32,924,109	4
							5
							6
							7
						32,924,109	8
							9
							10
							11
							12
							13
							14
							15
							16
						32,924,109	17
							18
						25,621,172	19
						7,302,937	20
							21

NOTES (Continued)

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

**Schedule Page: 272 Line No.: 8 Column: b**

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

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. NSP-Minnesota uses the average of the beginning of the year and the end of year accumulated income taxes balances in the formula.

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

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

Line No.	Account  (a)	Balance at Beginning of Year  (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1  (c)	Amounts Credited to Account 411.1  (d)
1	Account 282			
2	Electric	3,128,040,600	227,446,429	
3	Gas	202,484,279	14,147,381	
4				
5	TOTAL (Enter Total of lines 2 thru 4)	3,330,524,879	241,593,810	
6	Non-Operating	-56,241		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	3,330,468,638	241,593,810	
10	Classification of TOTAL			
11	Federal Income Tax	2,702,111,732	183,831,426	
12	State Income Tax	628,356,906	57,762,384	
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
		see note	88,178,473	see note	117,104,648	3,384,413,204	2
		see note	400,109	see note	588,014	216,819,565	3
							4
			88,578,582		117,692,662	3,601,232,769	5
80,794						24,553	6
							7
							8
80,794			88,578,582		117,692,662	3,601,257,322	9
							10
57,112			54,417,290		75,883,345	2,907,466,325	11
23,682			34,161,292		41,809,317	693,790,997	12
							13

NOTES (Continued)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

**Schedule Page: 274 Line No.: 2 Column: b**

Electric - Plant-Related:	Dec. 31, 2015	410.1 & Adjustments	Dec. 31, 2016
Electric Distribution Plant	\$728,279,615	\$62,651,708	\$790,931,323
Electric General Plant	76,601,641	7,890,235	84,491,876
Electric Intangible Plant	15,517,874	(1,848,298)	13,669,576
Electric Nuclear Fuel	69,179,630	(11,152,591)	58,027,039
Electric Nuclear Production Plant	592,863,506	14,110,279	606,973,785
Electric Production Plant	689,391,410	80,470,526	769,861,936
Electric Transmission Plant	680,511,366	69,940,637	750,452,003
Electric Transmission-Production Plant	16,034,383	4,334,960	20,369,343
Common (Allocation to Electric)	23,919,733	1,048,973	24,968,706
Regulatory Differences - Prior Flow Thru	(25,474,229)	(2,178,517)	(27,652,746)
Regulatory Differences - AFUDC Equity	197,596,868	2,371,228	199,968,096
Decommissioning Qualified	63,618,803	28,733,464	92,352,267
<b>Total Electric - Plant-Related</b>	<b>\$3,128,040,600</b>	<b>\$256,372,604</b>	<b>\$3,384,413,204</b>

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 in the formula. An adjustment is made to eliminate the accumulated deferred income tax balances related to regulatory differences related to income taxes.

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

Accounts No. 182.3, 254 & 281

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

Accounts No. 182.3, 254 & 282

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

Accounts No. 182.3, 254 & 282

**Schedule Page: 274 Line No.: 3 Column: i**

Accounts No. 182.3 & 254

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Electric - Plant	35,127,173	4,199,629	
4	Electric - Non-Plant	152,969,192	109,881,241	127,060,030
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	188,096,365	114,080,870	127,060,030
10	Gas			
11	Gas	30,907,874	29,479,875	22,811,126
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	30,907,874	29,479,875	22,811,126
18	Non Operating	77,596		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	219,081,835	143,560,745	149,871,156
20	Classification of TOTAL			
21	Federal Income Tax	177,015,444	112,844,824	118,056,613
22	State Income Tax	42,066,391	30,715,921	31,814,543
23	Local Income Tax			

NOTES

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				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
		182.3	137,464	see note	839	39,190,177	3
						135,790,403	4
							5
							6
							7
							8
			137,464		839	174,980,580	9
							10
				283		37,576,624	11
							12
							13
							14
							15
							16
						37,576,624	17
-3		283	1,219.1		524	78,116	18
-3			137,465		1,364	212,635,320	19
							20
2			104,468		478	171,699,667	21
-5			32,997		886	40,935,653	22
							23

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 04/10/2017	2016/Q4
FOOTNOTE DATA			

**Schedule Page: 276 Line No.: 3 Column: b**

Electric - Plant-Related:	Dec. 31, 2015	410.1 & Adjustments	Dec. 31, 2016
Electric Distribution Plant	\$186,665	(\$4,644)	\$182,021
Electric General Plant	(10,526)	5,010	(5,516)
Electric Intangible Plant	9,546,207	(3,840,615)	5,705,592
Electric Nuclear Production Plant	5,058,991	(575,549)	4,483,442
Electric Production Plant	49,880	(7,807)	42,073
Electric Transmission Plant	58,366	(1,378)	56,988
Common (Allocation to Electric)	17,607,690	8,624,612	26,232,302
Regulatory Differences - AFUDC Equity	2,629,900	(136,625)	2,493,275
Total Electric - Plant-Related	<u>\$35,127,173</u>	<u>\$4,063,004</u>	<u>\$39,190,177</u>

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 in the formula. An adjustment is made to eliminate the accumulated deferred income tax balances related to regulatory differences related to income taxes.

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

Accounts No. 182.3 and 283

**OTHER REGULATORY LIABILITIES (Account 254)**

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

Line No.	Description and Purpose of Other Regulatory Liabilities  (a)	Balance at Beginning of Current Quarter/Year  (b)	DEBITS		Credits  (e)	Balance at End of Current Quarter/Year  (f)
			Account Credited  (c)	Amount  (d)		
1	ITC Gross-up to Pre-Tax Rate Levels	19,289,017	190	1,286,564		18,002,453
2						
3	Deferred Tax Collected in Rates in Excess of Current Tax Accrual Levels	27,180,411			2,072,099	29,252,510
4						
5						
6	Unrealized Gains on Decommissioning Trust	164,897,017			74,475,819	239,372,836
7						
8	Gain from Sales of Emission Allowances	27,986	411.8	27,996	62	52
9	- ND Docket PU-12-813					
10	- Amortized over three years (01/2013-12/2016)					
11						
12	Electric Low Income Discount Program and PowerON Program	581,838	Various	11,626,060	12,123,618	1,079,396
13						
14	- MN Electric E-002/GR-13-868					
15	- MN Electric E-002/M-04-1956					
16						
17	Gas Low Income Discount Program	499,978	Various	2,519,708	2,084,441	64,711
18	- MN Gas G-002/GR-06-1429					
19						
20	Pre-ARO Decommissioning	1,468,068,325			34,533,640	1,502,601,965
21						
22	Derivatives & Hedging - Retail Electric & Gas	12,273,870			3,046,918	15,320,788
23						
24	Deferred Electric Commodity Costs	7,792,691			3,529,219	11,321,910
25						
26	Power Purchase Agreement	874,597	555	51,854	26,596	849,339
27						
28	South Dakota Transmission Cost Recovery Rider	516,197			299,467	815,664
29	- SD Docket EL15-030					
30						
31	Minnesota Gas State Energy Policy Rider	947,674	182.3	841,059		106,615
32	- MN Docket G-002/M-16-2016					
33						
34	Department of Energy Settlement Payment	11,623,138	142	12,260,974	14,470,641	13,832,805
35	- MN Docket E-002/M-15-1089					
36						
37	Department of Energy Settlement Payment	1,131,435	254	1,131,435		
38	Minnesota Decommissioning					
39	- MN Docket E-002/M-11-939					
40						
41	<b>TOTAL</b>	<b>1,733,392,392</b>		<b>41,820,630</b>	<b>176,885,056</b>	<b>1,868,456,818</b>

**OTHER REGULATORY LIABILITIES (Account 254)**

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

Line No.	Description and Purpose of Other Regulatory Liabilities  (a)	Balance at Beginning of Current Quarter/Year  (b)	DEBITS		Credits  (e)	Balance at End of Current Quarter/Year  (f)
			Account Credited  (c)	Amount  (d)		
1	Minnesota Retail Asset Margin Sharing	335,810	557	4,470,605	8,883,259	4,748,464
2	- MN Docket E-002/GR-12-961					
3						
4	North Dakota Retail Asset and Non-Asset	358,540	557	1,308,151	1,593,783	644,172
5	Margin Sharing					
6	- ND Docket PU-10-657					
7						
8	South Dakota Retail Asset and Non-Asset	616,264	557	2,335,407	1,971,606	252,463
9	Margin Sharing					
10	- SD Docket EL-12-046					
11						
12	South Dakota Production Tax Credit Sharing	5,146	557	2,876,603	4,548,992	1,677,535
13	- SD Docket EL-11-019					
14						
15	Minnesota Service Quality Program	979,009	142	700,619	293,110	571,500
16	- MN Docket E-002/M-16-281					
17	- MN Docket E-002/M-16-382					
18						
19	North Dakota Service Quality Program	75,000	142	284,825	409,700	199,875
20	- ND Docket PU-10-657					
21	- ND Docket PU-11-55					
22	- ND Docket PU-12-813					
23						
24	South Dakota Fuel Clause Adjustment Charge	3,285	431	8,860		-5,575
25	- SD EL-14-058					
26						
27	Transmission Formula Rates	9,051,488			4,700,240	13,751,728
28						
29	North Dakota ITC	5,678,792			1,896,237	7,575,029
30						
31	South Dakota Infrastructure	584,884	182.3	89,910		494,974
32	- SD Docket EL-15-038					
33						
34	Minnesota Revenue Decoupling				1,781,212	1,781,212
35	- MN Docket E-002/GR-13-868					
36						
37	North Dakota Renewable Energy Rider				353,061	353,061
38	- ND Docket PU-15-683					
39						
40						
41	<b>TOTAL</b>	<b>1,733,392,392</b>		<b>41,820,630</b>	<b>176,885,056</b>	<b>1,868,456,818</b>

**OTHER REGULATORY LIABILITIES (Account 254)**

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

Line No.	Description and Purpose of Other Regulatory Liabilities  (a)	Balance at Beginning of Current Quarter/Year  (b)	DEBITS		Credits  (e)	Balance at End of Current Quarter/Year  (f)
			Account Credited  (c)	Amount  (d)		
1	Minnesota Transmission Cost Recovery Rider				3,344,222	3,344,222
2	- MN Docket E-002/GR-13-868					
3	- MN Docket E-002/GR-15-891					
4						
5	Transco Administrative Services				213,617	213,617
6	Agreement					
7	- MN Docket E002/AI-14-759					
8	- MN Docket E002/AI-15-826					
9	- Amortized over three years (01/2016-12/2018)					
10						
11	Windsorce				233,497	233,497
12	- MN Docket E-002/M-01-1479					
13	- MN Docket E-002/GR-13-868					
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	<b>TOTAL</b>	1,733,392,392		41,820,630	176,885,056	1,868,456,818

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

**Schedule Page: 278 Line No.: 12 Column: c**

Accounts charged:

142	\$11,368,666
232	257,394
Total	<u>\$11,626,060</u>

**Schedule Page: 278 Line No.: 17 Column: c**

Accounts charged:

142	\$2,344,790
232	174,918
Total	<u>\$2,519,708</u>

**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	1,316,434,968	1,233,191,223
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,522,480,639	1,437,111,637
5	Large (or Ind.) (See Instr. 4)	686,231,582	669,773,812
6	(444) Public Street and Highway Lighting	26,402,371	25,831,661
7	(445) Other Sales to Public Authorities	9,176,485	8,385,549
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	654,722	790,906
10	TOTAL Sales to Ultimate Consumers	3,561,380,767	3,375,084,788
11	(447) Sales for Resale	83,071,627	115,713,391
12	TOTAL Sales of Electricity	3,644,452,394	3,490,798,179
13	(Less) (449.1) Provision for Rate Refunds	20,595,351	3,122,572
14	TOTAL Revenues Net of Prov. for Refunds	3,623,857,043	3,487,675,607
15	Other Operating Revenues		
16	(450) Forfeited Discounts	5,975,478	6,206,620
17	(451) Miscellaneous Service Revenues	3,061,422	3,328,027
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	5,014,177	4,789,673
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	483,031,757	489,884,799
22	(456.1) Revenues from Transmission of Electricity of Others	255,278,682	226,272,583
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	752,361,516	730,481,702
27	TOTAL Electric Operating Revenues	4,376,218,559	4,218,157,309

**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
10,107,329	9,987,615	1,291,114	1,279,780	2
				3
15,377,004	15,459,681	155,382	154,387	4
8,889,667	8,921,526	548	545	5
163,263	166,270	4,996	4,826	6
77,156	74,272	2,245	2,261	7
				8
7,500	10,334			9
34,621,919	34,619,698	1,454,285	1,441,799	10
6,897,102	4,864,428			11
41,519,021	39,484,126	1,454,285	1,441,799	12
				13
41,519,021	39,484,126	1,454,285	1,441,799	14

Line 12, column (b) includes \$ 24,392,831 of unbilled revenues.  
 Line 12, column (d) includes 334,198 MWH relating to unbilled revenues

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
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**

Retail interim rates	\$ (14,147,759)
Transmission rates	9,258,548
Retail rates - Monticello EPU	8,011,783
	<u>\$ 3,122,572</u>

Final rates in Minnesota electric docket 13-868 were higher than the interim rates billed, resulting in a credit provision for refund.

**Schedule Page: 300 Line No.: 17 Column: b**

Connection charges	\$ 2,738,661
NSF Check Fees	297,644
Other, less than \$250,000 each	25,117
	<u>\$ 3,061,422</u>

**Schedule Page: 300 Line No.: 17 Column: c**

Connection charges	\$ 2,959,644
NSF Check Fees	297,052
Other, less than \$250,000 each	71,331
	<u>\$ 3,328,027</u>

**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 Northern States Power Co. (a Wisconsin corporation) for production and transmission costs shared under the FERC-approved Interchange Agreement between the companies restated Jan. 16, 2001.

Northern States Power Co. (a Wisconsin corporation) and Northern States Power Co. (a Minnesota corporation) are both operating utility subsidiaries of Xcel Energy Inc. The two companies coordinate the operation and maintenance of their electric generation and transmission systems through the FERC-approved Interchange Agreement.

Fixed Production Expenses	\$ 239,774,694
Variable Production Expenses	181,754,204
Transmission Expenses	54,005,161
Total Interchange Agreement	<u>\$ 475,534,059</u>

Also includes the following items:

Fees charged to burn Refuse Derived Fuel	\$ 7,010,071
Windsor Program Revenue	5,251,481
Energy Services Revenue	629,402
Project Bid Fees	475,000

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)		04/10/2017	2016/Q4
FOOTNOTE DATA			

Work on Customers' Equipment	420,752
Conservation Improvement Program incentive, net of accruals and recoveries	(917,313)
Net distribution of commodity trading margins under Joint Operating Agreement	(2,199,587)
Change in net over-recovered electric commodity costs	(3,529,219)
Other, less than \$250,000 each	357,111
	\$ 483,031,757

**Schedule Page: 300 Line No.: 21 Column: c**

Includes reimbursement from Northern States Power Co. (a Wisconsin corporation) for production and transmission costs shared under the FERC-approved Interchange Agreement between the companies restated Jan. 16, 2001.

Northern States Power Co. (a Wisconsin corporation) and Northern States Power Co. (a Minnesota corporation) are both operating utility subsidiaries of Xcel Energy Inc. The two companies coordinate the operation and maintenance of their electric generation and transmission systems through the FERC-approved Interchange Agreement.

Fixed Production Expense	\$ 228,879,913
Variable Production Expense	197,322,241
Transmission Expense	46,896,539
Total Interchange Agreement	\$ 473,098,693

Also includes the following items:

Fees charged to burn Refuse Derived Fuel	\$ 6,780,747
Windsor source Program revenue	5,136,030
Net distribution of commodity trading margins under Joint Operating Agreement	2,457,334
Conservation Improvement Program incentive, net of accruals and recoveries	1,119,094
Change in net over-recovered electric commodity costs	557,513
Manitoba Hydro Transmission path re-assignment, energy service agreement and Tatanka transmission fees	539,226
Net MISO market Financial Transmission Rights activity	520,145
Energy Services revenue	516,908
Work on Customers' Equipment	393,706
Twin Cities Hydro distribution facilities charges	354,816
Mutual Aid revenue	294,315
Minnesota Cellnet Labor charges	267,376
Provision for refund under Minnesota and North Dakota jurisdiction	(1,254,077)
Service Quality Plans	
Production Tax Credit refunds	(2,108,435)
Other, less than \$250,000 each	1,211,408
	\$ 489,884,799

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

**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	183	22,075	42	4,357	0.1206
4	A01 Residential	4,859,090	653,872,838	748,557	6,491	0.1346
5	A02 Residential Time of Day	3,145	376,504	271	11,605	0.1197
6	A03 Residential Underground	3,651,327	478,850,157	378,561	9,645	0.1311
7	A04 Residential TOD Undergrnd	3,372	404,771	236	14,288	0.1200
8	A05 Energy Control	33,522	2,792,236	3,056	10,969	0.0833
9	A06 Limited Off Peak	2,605	207,586	381	6,837	0.0797
10	A07 Auto Protective Lighting	6,460	1,140,019			0.1765
11	A08 Residential Vehicle Tariff	158	13,274			0.0840
12	Unbilled	61,182	11,292,977			0.1846
13	North Dakota					
14	D01 Residential	577,866	61,599,461	67,887	8,512	0.1066
15	D02 Residential Time of Day	661	58,851	25	26,440	0.0890
16	D03 Residential Underground	156,112	15,559,677	12,088	12,915	0.0997
17	D04 Residential TOD Undergrnd	78	7,072	4	19,500	0.0907
18	D05 Energy Control	3,548	259,747	298	11,906	0.0732
19	D10 Limited Off Peak	690	45,534	109	6,330	0.0660
20	D11 Auto Protective Lighting	340	55,916			0.1645
21	Unbilled	4,965	289,263			0.0583
22	South Dakota					
23	E01 Residential	327,704	40,140,263	43,863	7,471	0.1225
24	E02 Residential Time of Day	19	1,817	3	6,333	0.0956
25	E03 Residential Underground	404,862	48,424,014	35,525	11,397	0.1196
26	E04 Residential Time of Day	43	4,875	3	14,333	0.1134
27	E06 Residential Heat Pump	1,584	137,553	102	15,529	0.0868
28	E10 Energy Control	1,295	96,087	103	12,573	0.0742
29	E11 Limited Off Peak	15	914			0.0609
30	E12 Auto Protective Lighting	354	65,725			0.1857
31	Unbilled	6,149	715,762			0.1164
32	Total Residential	10,107,329	1,316,434,968	1,291,114	7,828	0.1302
33						
34	COMMERCIAL AND INDUSTRIAL					
35	Minnesota					
36	A05 Energy Control	1,702	137,820	100	17,020	0.0810
37	A06 Limited Off Peak	1,975	165,115	84	23,512	0.0836
38	A07 Auto Protective Lighting	24,466	3,553,025			0.1452
39	A09 Small General Service	24	13,039	99	242	0.5433
40	A10 Small General Service	789,352	100,158,086	74,062	10,658	0.1269
41	TOTAL Billed	34,512,307	3,537,546,903	1,454,285	23,731	0.1025
42	Total Unbilled Rev.(See Instr. 6)	109,612	23,833,864	0	0	0.2174
43	TOTAL	34,621,919	3,561,380,767	1,454,285	23,807	0.1029

**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	A11 Water Heating	235	27,096	83	2,831	0.1153
2	A12 Small General TOD Service	42,829	4,710,750	2,854	15,007	0.1100
3	A13 Direct Current	3	8,415	3	1,000	2.8050
4	A14 General Service	8,133,189	833,358,473	40,333	201,651	0.1025
5	A15 General TOD Service	8,273,064	665,912,582	4,359	1,897,927	0.0805
6	A16 Small General kWh metered	13,494	1,739,452	2,897	4,658	0.1289
7	A18 Small General TOD Service	27,527	3,245,942	4,364	6,308	0.1179
8	A22 Small Gen TOD Low Watt	2,342	303,746	735	3,186	0.1297
9	A23 Peak Control Tiered	1,172,554	115,474,776	1,491	786,421	0.0985
10	A24 Peak Control Time of Day	2,524,313	194,053,362	355	7,110,741	0.0769
11	A27 Tier 1 Energy Control	393,517	24,069,327	14	28,108,357	0.0612
12	A29 Hiawatha Light Rail	23,763	2,159,403	16	1,485,188	0.0909
13	A63 Experimental Real Time	19,617	1,318,353	2	9,808,500	0.0672
14	Unbilled	25,231	10,449,429			0.4142
15	North Dakota					
16	D05 Energy Control	1,204	88,014	49	24,571	0.0731
17	D10 Limited Off Peak	571	45,456	33	17,303	0.0796
18	D11 Auto Protective Lighting	2,705	348,234			0.1287
19	D12 Small General Service	103,101	11,051,197	8,195	12,581	0.1072
20	D14 Small General TOD Service	2,076	208,032	194	10,701	0.1002
21	D16 General Service	715,905	67,495,614	3,586	199,639	0.0943
22	D17 General TOD Service	204,265	16,074,877	183	1,116,202	0.0787
23	D18 Small General TOD Service	559	63,556	101	5,535	0.1137
24	D19 Small General kWh metered	928	124,289	238	3,899	0.1339
25	D20 Peak Control	37,982	3,500,186	54	703,370	0.0922
26	D21 Peak Control Time of Day	130,101	9,167,596	13	10,007,769	0.0705
27	D22 Tier 1 Energy Control	235,126	16,006,985	69	3,407,623	0.0681
28	D34 Sm General TOD Low Watt	68	8,045	21	3,238	0.1183
29	Unbilled	5,896	252,903			0.0429
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	34,512,307	3,537,546,903	1,454,285	23,731	0.1025
42	Total Unbilled Rev.(See Instr. 6)	109,612	23,833,864	0	0	0.2174
43	TOTAL	34,621,919	3,561,380,767	1,454,285	23,807	0.1029

**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	South Dakota					
3	E10 Energy Control	128	9,478	8	16,000	0.0740
4	E11 Limited Off Peak	356	28,190	9	39,556	0.0792
5	E12 Auto Protective Lighting	2,278	365,624			0.1605
6	E13 Small General Service	87,713	9,957,813	7,315	11,991	0.1135
7	E14 Small General TOD Service	1,494	174,153	254	5,882	0.1166
8	E15 General Service	656,737	64,170,504	3,382	194,186	0.0977
9	E16 General TOD Service	462,437	36,167,656	202	2,289,292	0.0782
10	E18 Small General TOD Service	59	7,980	67	881	0.1353
11	E20 Peak Control	60,787	6,059,991	76	799,829	0.0997
12	21 Peak Control Time of Day	49,811	3,645,357	13	3,831,615	0.0732
13	E22 Energy Control	28,935	2,148,085	17	1,702,059	0.0742
14	Unbilled	6,252	684,215			0.1094
15	Total Commercial and Industrial	24,266,671	2,208,712,221	155,930	155,625	0.0910
16						
17	PUBLIC STREET AND HIGHWAY					
18	Minnesota					
19	A30 Street Light Co Owned	64,018	17,703,034	1,613	39,689	0.2765
20	A32 Street Light Cust Owned	33,344	2,444,505	434	76,829	0.0733
21	A34 Street Lighting Metered	36,480	2,614,612	2,344	15,563	0.0717
22	A37 Street Lighting St Paul	1,022	150,206	1	1,022,000	0.1470
23	Unbilled	36	121,474			3.3743
24	North Dakota					
25	D30 Street Light Co Owned	1,441	571,870	55	26,200	0.3969
26	D31 Street Light Cust Owned	11,748	920,563	33	356,000	0.0784
27	D32 Street Lighting Ornamental	37	3,574	2	18,500	0.0966
28	D33 Street Lighting Metered	1,762	112,726	80	22,025	0.0640
29	Unbilled	-105	-13,999			0.1333
30	South Dakota					
31	E30 Street Light Co Owned	1,813	767,355	93	19,495	0.4233
32	E31 Street Light Cust Owned	3,328	305,037	15	221,867	0.0917
33	E32 Street Lighting Metered	7,136	597,706	225	31,716	0.0838
34	E33 Street Lighting Ornamental	1,233	104,705	101	12,208	0.0849
35	Unbilled	-30	-997			0.0332
36	Total Public Street and Highway	163,263	26,402,371	4,996	32,679	0.1617
37						
38						
39						
40						
41	TOTAL Billed	34,512,307	3,537,546,903	1,454,285	23,731	0.1025
42	Total Unbilled Rev.(See Instr. 6)	109,612	23,833,864	0	0	0.2174
43	TOTAL	34,621,919	3,561,380,767	1,454,285	23,807	0.1029

**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	OTHER SALES TO PUBLIC					
3	Minnesota					
4	A40 Small Municipal Pumping	6,945	924,874	966	7,189	0.1332
5	A41 Municipal Pumping	56,945	6,802,859	565	100,788	0.1195
6	A42 Fire Siren		37,309	524		
7	Unbilled	155	56,329			0.3634
8	North Dakota					
9	D40 Small Municipal Pumping	746	83,961	79	9,443	0.1125
10	D41 Municipal Pumping	12,483	1,280,646	88	141,852	0.1026
11	D42 Fire Siren		1,044	23		
12	Unbilled	-118	-13,492			0.1143
13	South Dakota					
14	E40 Fire Siren		2,955			
15	Total Other Sales to Public Autho	77,156	9,176,485	2,245	34,368	0.1189
16						
17	Interdepartmental Sales	7,500	654,722			0.0873
18	Total Interdepartmental	7,500	654,722			0.0873
19						
20	Footnote for Instruction 5:					
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	34,512,307	3,537,546,903	1,454,285	23,731	0.1025
42	Total Unbilled Rev.(See Instr. 6)	109,612	23,833,864	0	0	0.2174
43	TOTAL	34,621,919	3,561,380,767	1,454,285	23,807	0.1029

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)		04/10/2017	2016/Q4
FOOTNOTE DATA			

**Schedule Page: 304.3 Line No.: 20 Column: a**

Estimated Fuel Revenue Collected Through Fuel Clause Adjustment:

A00	\$4,555
A01	118,231,525
A02	74,603
A03	89,274,699
A04	79,239
A05	887,473
A06	117,501
A07	563,340
A08	3,266
A09	625
A10	20,114,964
A11	6,004
A12	1,097,202
A13	89
A14	197,517,228
A15	197,017,892
A16	344,590
A18	701,361
A22	59,696
A23	28,441,847
A24	60,270,781
A27	9,241,785
A29	581,954
A30	1,165,170
A32	606,823
A34	663,788
A37	18,582
A40	177,516
A41	1,381,349
A50	91,695
A52	15,958
A63	456,897
	\$729,209,997

North Dakota

D01	\$13,399,133
D02	15,500
D03	3,618,485
D04	1,866
D05	116,309
D10	31,496
D11	52,208
D12	2,471,147
D14	49,226
D16	16,777,118
D17	4,608,006
D18	13,340
D19	22,118
D20	893,274
D21	2,882,057
D22	5,313,900
D30	25,338
D31	201,927

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)		04/10/2017	2016/Q4
FOOTNOTE DATA			

D32	628
D33	30,283
D34	1,619
D40	17,989
D41	292,427
North Dakota jurisdiction	<u>\$50,835,394</u>
South Dakota	
E01	\$7,421,426
E02	416
E03	9,159,291
E04	974
E06	36,439
E10	32,856
E11	8,799
E12	45,693
E13	2,008,658
E14	34,130
E15	14,764,945
E16	10,092,989
E18	1,354
E20	1,369,100
E21	1,090,086
E22	640,437
E30	31,508
E31	57,971
E32	124,148
E33	\$21,405
South Dakota jurisdiction	<u>\$46,942,625</u>
Total Company	<u>\$826,988,016</u>

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 not 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 long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.  
 IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.  
 SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.  
 LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.  
 IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

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)	Average Monthly CP Demand (f)
1	NSP-Wisconsin	RQ		N/A	N/A	N/A
2	Basin Electric Power Cooperative	OS	V6	N/A	N/A	N/A
3	BP Energy Company	OS	V6	N/A	N/A	N/A
4	Central Minnesota Municipal Pwr Agency	OS	V6	N/A	N/A	N/A
5	City of Ada, MN	OS	V6	N/A	N/A	N/A
6	City of Ada, MN	SF	V6	N/A	N/A	N/A
7	City of Kasota, MN	OS	V6	N/A	N/A	N/A
8	City of Kasota, MN	SF	V6	N/A	N/A	N/A
9	Conoco Phillips Company	OS	V6	N/A	N/A	N/A
10	Dahlberg Light and Power Co.	OS	V6	N/A	N/A	N/A
11	Dahlberg Light and Power Co.	SF	V6	N/A	N/A	N/A
12	Exelon Generation Company	OS	V6	N/A	N/A	N/A
13	Interstate Power and Light	OS	V6	N/A	N/A	N/A
14	MidAmerican Energy Company	OS	V6	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	<b>Total</b>			<b>0</b>	<b>0</b>	<b>0</b>



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, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
5,922,958		358,511,283		358,511,283	1
	600,000			600,000	2
32,800			851,890	851,890	3
104,908		2,203,311		2,203,311	4
	61,500			61,500	5
5,905		549,058		549,058	6
	31,980			31,980	7
3,965		251,180		251,180	8
33,600			911,731	911,731	9
4,899	232,160	110,357		342,517	10
114,232		5,439,085		5,439,085	11
800			14,800	14,800	12
	84,500			84,500	13
4,000			80,000	80,000	14
5,922,958	0	358,511,283	0	358,511,283	
6,897,102	2,193,338	73,077,825	7,800,464	83,071,627	
<b>12,820,060</b>	<b>2,193,338</b>	<b>431,589,108</b>	<b>7,800,464</b>	<b>441,582,910</b>	

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, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
6,262,199	444,608	58,082,147	2,401,882	60,928,637	1
	84,000			84,000	2
	137,500			137,500	3
	106,250			106,250	4
120,000			3,518,161	3,518,161	5
14,728	67,745	266,439		334,184	6
12,864		485,544		485,544	7
55,594	343,095	1,049,416		1,392,511	8
125,808		4,641,288		4,641,288	9
800			22,000	22,000	10
					11
					12
					13
					14
5,922,958	0	358,511,283	0	358,511,283	
6,897,102	2,193,338	73,077,825	7,800,464	83,071,627	
<b>12,820,060</b>	<b>2,193,338</b>	<b>431,589,108</b>	<b>7,800,464</b>	<b>441,582,910</b>	

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
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.: 2 Column: c**

V6 - FERC Electric Tariff, First Revised Volume No. 6

**Schedule Page: 310 Line No.: 3 Column: j**

Financial Trading

**Schedule Page: 310 Line No.: 9 Column: j**

Financial Trading

**Schedule Page: 310 Line No.: 12 Column: j**

Financial Trading

**Schedule Page: 310 Line No.: 14 Column: j**

Financial Trading

**Schedule Page: 310.1 Line No.: 1 Column: j**

Demand - Resource Adequacy Action, Other - Ancillary services

**Schedule Page: 310.1 Line No.: 5 Column: j**

Financial Trading

**Schedule Page: 310.1 Line No.: 10 Column: j**

Financial Trading

**Schedule Page: 310.1 Line No.: 12 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.

	Revenue	Mwh
page 300, line 11(b)	\$83,071,627	6,897,102
page 311 total (k)	\$441,582,910	12,820,060
less net interchange agreement	(358,511,283)	(5,922,958)
	\$83,071,627	6,897,102

**Schedule Page: 310.1 Line No.: 13 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.

**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	4,002,410	5,260,082
5	(501) Fuel	292,786,848	334,484,832
6	(502) Steam Expenses	20,140,543	19,947,733
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	4,742,224	4,453,624
10	(506) Miscellaneous Steam Power Expenses	18,418,746	20,621,701
11	(507) Rents	3,700,748	2,899,500
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	343,791,519	387,667,472
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,720,065	2,539,883
16	(511) Maintenance of Structures	7,163,883	7,119,441
17	(512) Maintenance of Boiler Plant	32,136,719	35,287,182
18	(513) Maintenance of Electric Plant	10,288,687	12,890,806
19	(514) Maintenance of Miscellaneous Steam Plant	15,501,525	14,718,436
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	67,810,879	72,555,748
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	411,602,398	460,223,220
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	71,715,041	68,885,785
25	(518) Fuel	116,981,547	106,424,403
26	(519) Coolants and Water	8,674,239	8,558,269
27	(520) Steam Expenses	47,803,622	48,558,925
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	4,147,206	2,181,969
31	(524) Miscellaneous Nuclear Power Expenses	138,059,327	137,686,669
32	(525) Rents	10,763,466	10,584,494
33	TOTAL Operation (Enter Total of lines 24 thru 32)	398,144,448	382,880,514
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	6,647,149	8,331,495
36	(529) Maintenance of Structures	845,272	685,835
37	(530) Maintenance of Reactor Plant Equipment	42,572,905	38,944,100
38	(531) Maintenance of Electric Plant	17,491,413	19,566,892
39	(532) Maintenance of Miscellaneous Nuclear Plant	30,900,109	44,402,887
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	98,456,848	111,931,209
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	496,601,296	494,811,723
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	2,201	1,294
45	(536) Water for Power	663	
46	(537) Hydraulic Expenses		1,088
47	(538) Electric Expenses	206,041	200,427
48	(539) Miscellaneous Hydraulic Power Generation Expenses	147,274	147,539
49	(540) Rents	23,244	17,596
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	379,423	367,944
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	25,154	3,899
54	(542) Maintenance of Structures	86,278	64,335
55	(543) Maintenance of Reservoirs, Dams, and Waterways	45,098	106,180
56	(544) Maintenance of Electric Plant	31,618	33,673
57	(545) Maintenance of Miscellaneous Hydraulic Plant	7,970	19,460
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	196,118	227,547
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	575,541	595,491

**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	944,062	1,075,250
63	(547) Fuel	145,528,076	163,685,273
64	(548) Generation Expenses	11,534,509	8,279,695
65	(549) Miscellaneous Other Power Generation Expenses	6,893,868	6,047,758
66	(550) Rents	1,446,954	1,229,970
67	TOTAL Operation (Enter Total of lines 62 thru 66)	166,347,469	180,317,946
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	476,689	737,897
70	(552) Maintenance of Structures	4,401,881	3,147,071
71	(553) Maintenance of Generating and Electric Plant	9,802,663	9,128,900
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	6,700,326	2,163,839
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	21,381,559	15,177,707
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	187,729,028	195,495,653
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	670,501,522	765,036,899
77	(556) System Control and Load Dispatching	1,198,665	1,274,646
78	(557) Other Expenses	73,921,202	89,165,471
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	745,621,389	855,477,016
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,842,129,652	2,006,603,103
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	11,141,883	9,626,515
84			
85	(561.1) Load Dispatch-Reliability		93,311
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	5,980,333	6,124,802
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	7,057,099	6,963,995
89	(561.5) Reliability, Planning and Standards Development	8,451	75,572
90	(561.6) Transmission Service Studies	-5,280	
91	(561.7) Generation Interconnection Studies	10,641	-12,231
92	(561.8) Reliability, Planning and Standards Development Services	2,930,972	2,549,889
93	(562) Station Expenses	1,568,807	1,387,300
94	(563) Overhead Lines Expenses	1,263,292	1,780,386
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	193,894,526	167,127,215
97	(566) Miscellaneous Transmission Expenses	112,069,854	98,269,153
98	(567) Rents	2,879,927	2,190,831
99	TOTAL Operation (Enter Total of lines 83 thru 98)	338,800,505	296,176,738
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	180,957	109,947
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	7,526,675	6,143,250
108	(571) Maintenance of Overhead Lines	8,923,868	6,905,025
109	(572) Maintenance of Underground Lines	289,207	24,850
110	(573) Maintenance of Miscellaneous Transmission Plant	30,414	82,504
111	TOTAL Maintenance (Total of lines 101 thru 110)	16,951,121	13,265,576
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	355,751,626	309,442,314

**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	<b>3. REGIONAL MARKET EXPENSES</b>		
114	Operation		
115	(575.1) Operation Supervision	184,996	202,228
116	(575.2) Day-Ahead and Real-Time Market Facilitation	112,413	72,842
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation	59,896	21,614
120	(575.6) Market Monitoring and Compliance	14,905	17,791
121	(575.7) Market Facilitation, Monitoring and Compliance Services	9,204,811	9,118,563
122	(575.8) Rents	6,269	15,793
123	Total Operation (Lines 115 thru 122)	9,583,290	9,448,831
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 Exps (Total 123 and 130)	9,583,290	9,448,831
132	<b>4. DISTRIBUTION EXPENSES</b>		
133	Operation		
134	(580) Operation Supervision and Engineering	9,779,861	10,147,712
135	(581) Load Dispatching	3,333,688	6,382,391
136	(582) Station Expenses	3,461,795	3,032,582
137	(583) Overhead Line Expenses	2,322,654	976,590
138	(584) Underground Line Expenses	7,511,589	6,189,811
139	(585) Street Lighting and Signal System Expenses	1,087,263	1,731,993
140	(586) Meter Expenses	1,453,214	1,598,608
141	(587) Customer Installations Expenses	3,717,411	1,432,902
142	(588) Miscellaneous Expenses	12,289,770	11,931,941
143	(589) Rents	4,030,969	3,842,845
144	TOTAL Operation (Enter Total of lines 134 thru 143)	48,988,214	47,267,375
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	367,998	616,392
147	(591) Maintenance of Structures	238	
148	(592) Maintenance of Station Equipment	9,177,185	8,353,473
149	(593) Maintenance of Overhead Lines	38,163,776	34,051,009
150	(594) Maintenance of Underground Lines	10,162,873	11,968,062
151	(595) Maintenance of Line Transformers	2,364,795	2,537,324
152	(596) Maintenance of Street Lighting and Signal Systems	1,626,677	1,545,700
153	(597) Maintenance of Meters	109,271	105,988
154	(598) Maintenance of Miscellaneous Distribution Plant	8,179	6,239
155	TOTAL Maintenance (Total of lines 146 thru 154)	61,980,992	59,184,187
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	110,969,206	106,451,562
157	<b>5. CUSTOMER ACCOUNTS EXPENSES</b>		
158	Operation		
159	(901) Supervision	118,011	117,352
160	(902) Meter Reading Expenses	19,520,967	19,076,415
161	(903) Customer Records and Collection Expenses	23,841,892	24,151,248
162	(904) Uncollectible Accounts	12,514,661	12,004,811
163	(905) Miscellaneous Customer Accounts Expenses	621	1
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	55,996,152	55,349,827

**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	<b>6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES</b>		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	88,612,847	68,218,510
169	(909) Informational and Instructional Expenses	1,322,748	1,235,344
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	<b>TOTAL Customer Service and Information Expenses (Total 167 thru 170)</b>	<b>89,935,595</b>	<b>69,453,854</b>
172	<b>7. SALES EXPENSES</b>		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	1,482	2,110
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	<b>TOTAL Sales Expenses (Enter Total of lines 174 thru 177)</b>	<b>1,482</b>	<b>2,110</b>
179	<b>8. ADMINISTRATIVE AND GENERAL EXPENSES</b>		
180	Operation		
181	(920) Administrative and General Salaries	72,782,921	76,299,639
182	(921) Office Supplies and Expenses	56,649,158	52,605,695
183	(Less) (922) Administrative Expenses Transferred-Credit	41,946,226	37,442,700
184	(923) Outside Services Employed	28,050,158	23,828,798
185	(924) Property Insurance	7,358,647	9,244,456
186	(925) Injuries and Damages	11,951,414	14,942,919
187	(926) Employee Pensions and Benefits	88,142,330	83,907,276
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	7,748,595	9,328,994
190	(929) (Less) Duplicate Charges-Cr.	4,899,638	4,702,073
191	(930.1) General Advertising Expenses	3,077,317	2,748,734
192	(930.2) Miscellaneous General Expenses	3,315,655	3,017,246
193	(931) Rents	31,089,269	27,734,109
194	<b>TOTAL Operation (Enter Total of lines 181 thru 193)</b>	<b>263,319,600</b>	<b>261,513,093</b>
195	Maintenance		
196	(935) Maintenance of General Plant	2,212,100	1,565,900
197	<b>TOTAL Administrative &amp; General Expenses (Total of lines 194 and 196)</b>	<b>265,531,700</b>	<b>263,078,993</b>
198	<b>TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)</b>	<b>2,729,898,703</b>	<b>2,819,830,594</b>

--	--	--	--

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

**Schedule Page: 320 Line No.: 64 Column: b**

Account No. 548 Generation Expenses	\$ 11,525,485
Account No. 548.1 Operation of Energy Storage Equipment	9,024
	<u>\$ 11,534,509</u>

See Note 15 to the Financial Statements

**Schedule Page: 320 Line No.: 64 Column: c**

Account No. 548 Generation Expenses	\$ 8,279,695
Account No. 548.1 Operation of Energy Storage Equipment	
	<u>\$ 8,279,695</u>

See Note 15 to the Financial Statements

**Schedule Page: 320 Line No.: 71 Column: b**

Account No. 553 Maintenance of Generating and Electric Plant	\$ 9,724,606
Account No. 553.1 Maintenance of Energy Storage Equipment	78,057
	<u>\$ 9,802,663</u>

See Note 15 to the Financial Statements

**Schedule Page: 320 Line No.: 71 Column: c**

Account No. 553 Maintenance of Generating and Electric Plant	\$ 9,019,682
Account No. 553.1 Maintenance of Energy Storage Equipment	109,218
	<u>\$ 9,128,900</u>

See Note 15 to the Financial Statements

**Schedule Page: 320 Line No.: 76 Column: b**

Account No. 555 Purchased Power	\$670,498,313
Account No. 555.1 Power Purchased for Storage Operations	3,209
	<u>\$670,501,522</u>

See Note 15 to the Financial Statements

**Schedule Page: 320 Line No.: 76 Column: c**

Account No. 555 Purchased Power	\$765,067,809
Account No. 555.1 Power Purchased for Storage Operations	(30,910)
	<u>\$765,036,899</u>

See Note 15 to the Financial Statements

**Schedule Page: 320 Line No.: 78 Column: b**

Includes \$46,601,900 of fixed costs and \$16,415,715 of variable costs reimbursed to Northern States Power Co. (a Wisconsin corporation) for production costs shared through the FERC-approved Interchange Agreement.

Northern States Power Co. (a Minnesota corporation) and Northern States Power Co. (a Wisconsin corporation) are both operating utility subsidiaries of Xcel Energy Inc. The two companies coordinate the operation and maintenance of their electric generation and transmission systems through a FERC-approved Interchange Agreement.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

**Schedule Page: 320 Line No.: 78 Column: c**

Includes \$52,974,220 of fixed costs and \$17,529,413 of variable costs reimbursed to Northern States Power Co. (a Wisconsin corporation) for production costs shared through the FERC-approved Interchange Agreement.

Northern States Power Co. (a Minnesota corporation) and Northern States Power Co. (a Wisconsin corporation) are both operating utility subsidiaries of Xcel Energy Inc. The two companies coordinate the operation and maintenance of their electric generation and transmission systems through a FERC-approved Interchange Agreement.

**Schedule Page: 320 Line No.: 91 Column: c**

Credit balance results from prepaid bid fees related to the utility scale solar program, and also because Pension, Insurance and Taxes on Company labor billed for performing generation interconnection studies is 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.: 97 Column: b**

Includes \$107,465,543 of fixed costs reimbursed to Northern States Power Co. (a Wisconsin corporation) for transmission costs shared through the FERC-approved Interchange Agreement.

Northern States Power Co. (a Minnesota corporation) and Northern States Power Co. (a Wisconsin corporation) are both operating utility subsidiaries of Xcel Energy Inc. The two companies coordinate the operation and maintenance of their electric generation and transmission systems through the FERC-approved Interchange Agreement.

**Schedule Page: 320 Line No.: 97 Column: c**

Includes \$92,751,312 of fixed costs reimbursed to Northern States Power Co. (a Wisconsin corporation) for transmission costs shared through the FERC-approved Interchange Agreement.

Northern States Power Co. (a Minnesota corporation) and Northern States Power Co. (a Wisconsin corporation) are both operating utility subsidiaries of Xcel Energy Inc. The two companies coordinate the operation and maintenance of their electric generation and transmission systems through the FERC-approved Interchange Agreement.

**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.

**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)	Average Monthly CP Demand (f)
1	Adams Wind Generations, LLC	LU		N/A	N/A	N/A
2	Agassiz Beach LLC	LU		N/A	N/A	N/A
3	Benson Power, LLC	LU		N/A	N/A	N/A
4	Best Power International LLC	LU		N/A	N/A	N/A
5	Big Blue	LU		N/A	N/A	N/A
6	Bisson Windfarm, L.L.C.	LU		N/A	N/A	N/A
7	Boeve Windfarm, L.L.C.	LU		N/A	N/A	N/A
8	Buffalo Ridge Wind Energy, LLC	AD		N/A	N/A	N/A
9	Buffalo Ridge Wind Energy, LLC	LU		N/A	N/A	N/A
10	Byllesby	LU		2	N/A	N/A
11	Cannon Falls Energy Center	LU		347	N/A	N/A
12	Carleton College	LU		N/A	N/A	N/A
13	CG Windfarm, L.L.C.	LU		N/A	N/A	N/A
14	Chanarambie Power Partners, L.L.C.	LU		N/A	N/A	N/A
	<b>Total</b>					



**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)	Average Monthly CP Demand (f)
1	Fey Windfarm, L.L.C.	LU		N/A	N/A	N/A
2	FPL Energy Mower County, L.L.C.	LU		N/A	N/A	N/A
3	Garwin McNeilus	LU		N/A	N/A	N/A
4	Grant County Wind, LLC	LU		N/A	N/A	N/A
5	Hastings Lock & Dam	LU		2	N/A	N/A
6	Hilltop Power, L.L.C.	LU		N/A	N/A	N/A
7	Jeffers Wind Energy Center	LU		N/A	N/A	N/A
8	JJN Windfarm, LLC	AD		N/A	N/A	N/A
9	JJN Windfarm, LLC	LU		N/A	N/A	N/A
10	Kas Brothers Windfarm, L.L.C.	LU		N/A	N/A	N/A
11	K-Brink Windfarm, L.L.C.	LU		N/A	N/A	N/A
12	KODA Energy, LLC	LU		N/A	N/A	N/A
13	Lake Benton Power Partners, L.L.C.	LU		N/A	N/A	N/A
14	Laurentian Energy Authority, L.L.C.	AD		N/A	N/A	N/A
	<b>Total</b>					

**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)	Average Monthly CP Demand (f)
1	Laurentian Energy Authority, L.L.C.	LU		N/A	N/A	N/A
2	LCO Hydro	LU		N/A	N/A	N/A
3	Lincoln Heights Wind Holdings	LU		N/A	N/A	N/A
4	LSP Cottage Grove Incorporated	LU		245	N/A	N/A
5	Luverne Battery	OS		N/A	N/A	N/A
6	Manitoba Hydro	LU		350	N/A	N/A
7	Mankato Energy Center, L.L.C.	LU		375	N/A	N/A
8	Marshall Solar	LU		N/A	N/A	N/A
9	Metro Wind LLC	LU		N/A	N/A	N/A
10	Midcontinental ISO	AD		N/A	N/A	N/A
11	Midcontinental ISO	SF		N/A	N/A	N/A
12	MinnDakota	LU		N/A	N/A	N/A
13	Minnkota Power Company	AD		N/A	N/A	N/A
14	Miscellaneous	OS		N/A	N/A	N/A
	<b>Total</b>					

**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)	Average Monthly CP Demand (f)
1	Moraine Wind, L.L.C.	LU		N/A	N/A	N/A
2	NAE Lakota Ridge, LLC	LU		N/A	N/A	N/A
3	NAE Shaokatan, LLC	LU		N/A	N/A	N/A
4	NAE Shaokatan Hills, LLC	LU		N/A	N/A	N/A
5	Natural Gas Exchange Inc.	OS		N/A	N/A	N/A
6	Neshkoro (Neshonoc)	LU		.4	N/A	N/A
7	New England ISO	OS		N/A	N/A	N/A
8	New Ulm	OS	NAEM	N/A	N/A	N/A
9	New York ISO	OS		N/A	N/A	N/A
10	North Community Turbines LLC	LU		N/A	N/A	N/A
11	North Star Solar	LU		N/A	N/A	N/A
12	North Wind Turbines LLC	LU		N/A	N/A	N/A
13	NSP-M Solar Gardens	LU		N/A	N/A	N/A
14	Odell Wind Farm, LLC	LU		N/A	N/A	N/A
	<b>Total</b>					

**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)	Average Monthly CP Demand (f)
1	Olsen Windfarms	LU		N/A	N/A	N/A
2	Pine Bend	LU		N/A	N/A	N/A
3	Pipestone	LU		N/A	N/A	N/A
4	PJM Interconnection LLC	AD		N/A	N/A	N/A
5	PJM Interconnection LLC	OS		N/A	N/A	N/A
6	Prairie Rose Wind LLC	AD		N/A	N/A	N/A
7	Prairie Rose Wind LLC	LU		N/A	N/A	N/A
8	Rapidan Hydroelectric Facility	LU		2	N/A	N/A
9	Ridgewind Power Partners, LLC	LU		N/A	N/A	N/A
10	Rock County Energy	LU		N/A	N/A	N/A
11	Rock Ridge Power Partners LLC	LU		N/A	N/A	N/A
12	Ruthon Ridge LLC	LU		N/A	N/A	N/A
13	SAF Hydroelectric, L.L.C.	LU		N/A	N/A	N/A
14	Shane's Wind Machine LLC	LU		N/A	N/A	N/A
	<b>Total</b>					

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)	Average Monthly CP Demand (f)
1	Slayton Solar, LLC	LU		N/A	N/A	N/A
2	South Ridge	LU		N/A	N/A	N/A
3	Southern Minnesota Municipal Power Acy	OS		N/A	N/A	N/A
4	Southwest Power Pool Electric Energy	AD		N/A	N/A	N/A
5	Southwest Power Pool Electric Energy	OS		N/A	N/A	N/A
6	St Cloud	LU		7	N/A	N/A
7	St. Olaf College	LU		N/A	N/A	N/A
8	St. Paul Cogeneration	LU		N/A	N/A	N/A
9	TG Windfarm, L.L.C.	LU		N/A	N/A	N/A
10	Tholen	LU		N/A	N/A	N/A
11	Tofteland Windfarm, L.L.C.	LU		N/A	N/A	N/A
12	Uilk Wind Farm, LLC	LU		N/A	N/A	N/A
13	University of Minnesota	AD		N/A	N/A	N/A
14	University of Minnesota	LU		N/A	N/A	N/A
	Total					

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)	Average Monthly CP Demand (f)
1	Valley View Transmission	LU		N/A	N/A	N/A
2	Velva Windfarm, LLC	LU		N/A	N/A	N/A
3	Viking Wind Partners	LU		N/A	N/A	N/A
4	Western Area Power Administration	LU	NAEM, WSPP	N/A	N/A	N/A
5	Westridge Windfarm, L.L.C.	LU		N/A	N/A	N/A
6	Windcurrent Farms, L.L.C.	LU		N/A	N/A	N/A
7	Windvest	LU		N/A	N/A	N/A
8	Winona County Wind LLC	LU		N/A	N/A	N/A
9	WM Renewable Energy, LLC	LU		N/A	N/A	N/A
10	Woodstock Hills, L.L.C.	LU		N/A	N/A	N/A
11	Woodstock Municipal Wind, LLC	LU		N/A	N/A	N/A
12	Zephyr Wind	LU		N/A	N/A	N/A
13						
14						
	Total					

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 monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. 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)	
57,476				3,965,831		3,965,831	1
5,285				122,345		122,345	2
344,054				56,480,353		56,480,353	3
1,897				164,777		164,777	4
119,255				6,131,738		6,131,738	5
556				18,941		18,941	6
5,512				184,630		184,630	7
				-78,731		-78,731	8
25,288				979,423		979,423	9
15,563			422,801	280,056		702,857	10
173,348			26,664,824	8,284,300		34,949,124	11
4,368				144,119		144,119	12
-431				-14,624		-14,624	13
232,290				6,411,581		6,411,581	14
13,203,184			153,618,389	511,616,692	5,266,441	670,501,522	

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 monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. 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)	
28,043				1,401,259		1,401,259	1
193,000			7,523,917	3,773,381		11,297,298	2
543				17,267		17,267	3
17,200				299,968		299,968	4
53,515				3,660,390		3,660,390	5
673				41,290		41,290	6
26,727				881,871		881,871	7
16,800					405,544	405,544	8
					-177	-177	9
					-73,918	-73,918	10
-10,000					-360,253	-360,253	11
71,153				3,130,732		3,130,732	12
800					33,600	33,600	13
734,140				33,702,116		33,702,116	14
13,203,184			153,618,389	511,616,692	5,266,441	670,501,522	

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 monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. 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)	
6,095				213,321		213,321	1
301,997				12,659,899		12,659,899	2
76,392				2,503,012		2,503,012	3
64,930				4,486,683		4,486,683	4
18,935			455,856	304,527		760,383	5
2,685				139,628		139,628	6
171,204				6,277,533		6,277,533	7
				38,276		38,276	8
4,528				113,637		113,637	9
3,889				145,564		145,564	10
4,337				145,190		145,190	11
99,975				8,103,444		8,103,444	12
506,747				15,220,267		15,220,267	13
				-17,471		-17,471	14
13,203,184			153,618,389	511,616,692	5,266,441	670,501,522	

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 monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. 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)	
264,543				31,948,493		31,948,493	1
15,688				454,071		454,071	2
23,332				796,929		796,929	3
367,647			45,911,302	9,412,942		55,324,244	4
676				3,209		3,209	5
1,703,034			33,615,330	91,685,191		125,300,521	6
874,484			36,786,410	22,788,717		59,575,127	7
3,185				131,110		131,110	8
886				22,170		22,170	9
-36,079				333,248		333,248	10
3,221,437				34,788,990		34,788,990	11
561,285				21,909,910		21,909,910	12
				-72		-72	13
					403,913	403,913	14
13,203,184			153,618,389	511,616,692	5,266,441	670,501,522	

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 monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. 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)	
327,689				15,168,356		15,168,356	1
25,687				1,195,037		1,195,037	2
32,530				811,301		811,301	3
32,747				1,521,778		1,521,778	4
182,000					5,151,531	5,151,531	5
2,548			77,784	43,177		120,961	6
					15,003	15,003	7
			405,000			405,000	8
					52,044	52,044	9
50,970				3,363,860		3,363,860	10
13,455				614,688	-350,000	264,688	11
48,219				3,182,445		3,182,445	12
396				52,989		52,989	13
341,758				7,316,302		7,316,302	14
13,203,184			153,618,389	511,616,692	5,266,441	670,501,522	

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 monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. 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)	
2,638				97,931		97,931	1
36,538				1,796,604		1,796,604	2
25,455				839,675		839,675	3
					-4,841	-4,841	4
					-6,005	-6,005	5
				2,546		2,546	6
700,176				25,271,852		25,271,852	7
16,142			347,235	270,849		618,084	8
89,130				6,042,055		6,042,055	9
17,006				561,030		561,030	10
7,237				238,825		238,825	11
48,649				1,062,050		1,062,050	12
48,865				2,380,133		2,380,133	13
7,628				251,774		251,774	14
13,203,184			153,618,389	511,616,692	5,266,441	670,501,522	

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 monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. 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)	
2,726				310,609		310,609	1
7,212				237,924		237,924	2
172,774				2,641,170		2,641,170	3
-59				-6,476		-6,476	4
4,809				131,063		131,063	5
56,691			1,407,930	921,563		2,329,493	6
40				1,241		1,241	7
153,880				23,076,392		23,076,392	8
12				415		415	9
45,646				1,506,299		1,506,299	10
4,218				132,333		132,333	11
14,343				974,451		974,451	12
				1,861		1,861	13
3,305				60,983		60,983	14
13,203,184			153,618,389	511,616,692	5,266,441	670,501,522	

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 monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. 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)	
29,916				1,957,058		1,957,058	1
28,602				943,841		943,841	2
37,216				1,219,714		1,219,714	3
11,851				395,144		395,144	4
3,837				134,245		134,245	5
5,296				185,306		185,306	6
7,098				234,289		234,289	7
84				5,740		5,740	8
38,413				1,728,509		1,728,509	9
17,145				740,739		740,739	10
2,270				154,047		154,047	11
119,509				7,251,544		7,251,544	12
							13
							14
13,203,184			153,618,389	511,616,692	5,266,441	670,501,522	

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

<b>Schedule Page: 326 Line No.: 3 Column: k</b> Formerly FibroMinn
<b>Schedule Page: 326 Line No.: 8 Column: k</b> Prior Period Adjustment
<b>Schedule Page: 326 Line No.: 9 Column: k</b> Formerly Windpower Partners 1993, Limited Partnership
<b>Schedule Page: 326 Line No.: 13 Column: k</b> Housepower
<b>Schedule Page: 326.1 Line No.: 3 Column: k</b> Prior Period Adjustment
<b>Schedule Page: 326.1 Line No.: 8 Column: l</b> Financial Trading
<b>Schedule Page: 326.1 Line No.: 9 Column: l</b> Prior Period Adjustment
<b>Schedule Page: 326.1 Line No.: 10 Column: l</b> Comp. for Non-Renewable Energy Rebate
<b>Schedule Page: 326.1 Line No.: 11 Column: l</b> Financial Trading
<b>Schedule Page: 326.1 Line No.: 13 Column: l</b> Financial Trading
<b>Schedule Page: 326.2 Line No.: 8 Column: k</b> Prior Period Adjustment
<b>Schedule Page: 326.2 Line No.: 14 Column: k</b> Prior Period Adjustment
<b>Schedule Page: 326.3 Line No.: 3 Column: k</b> Formerly John Deere Renewables, L.L.C.
<b>Schedule Page: 326.3 Line No.: 5 Column: k</b> Refer to Footnote 15 on page 123 for further information regarding the Luverne Battery Project.
<b>Schedule Page: 326.3 Line No.: 10 Column: k</b> Prior Period Adjustment
<b>Schedule Page: 326.3 Line No.: 13 Column: k</b> Prior Period Adjustment
<b>Schedule Page: 326.3 Line No.: 14 Column: l</b> Miscellaneous
<b>Schedule Page: 326.4 Line No.: 5 Column: l</b> Financial Trading
<b>Schedule Page: 326.4 Line No.: 7 Column: l</b> Financial Trading
<b>Schedule Page: 326.4 Line No.: 8 Column: j</b> Capacity Credits
<b>Schedule Page: 326.4 Line No.: 9 Column: l</b> Financial Trading
<b>Schedule Page: 326.4 Line No.: 11 Column: l</b> Delay Damages
<b>Schedule Page: 326.5 Line No.: 4 Column: l</b> Prior Period Adjustment
<b>Schedule Page: 326.5 Line No.: 5 Column: l</b> Financial Trading
<b>Schedule Page: 326.5 Line No.: 6 Column: k</b> Prior Period Adjustment
<b>Schedule Page: 326.5 Line No.: 10 Column: k</b> Formerly Minwind Energy, L.L.C.
<b>Schedule Page: 326.6 Line No.: 3 Column: k</b>

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Financial Trading

**Schedule Page: 326.6 Line No.: 4 Column: k**

Prior Period Adjustment

**Schedule Page: 326.6 Line No.: 5 Column: k**

Financial Trading

**Schedule Page: 326.6 Line No.: 13 Column: k**

Prior Period Adjustment

**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 Classification (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	Minnesota Municipal Power Agency (MMPA)	Various	Various	AD
6	Missouri River Energy Services (MRES)	Various	Various	FNO
7	Sioux Falls, City of	WAPA	Sioux Falls, City of	OS
8	South Dakota State Penitentiary (SDSP)	WAPA	SDSP	OS
9	Southern MN Municipal Power Agency	Various	Various	FNO
10	University of North Dakota	WAPA	University of North Dakota	OS
11	Wisconsin Public Power (WPPI)	MP	WPPI	OS
12				
13				
14				
15				
16				
17				
18				
19	**Footnote from page 106b			
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	<b>TOTAL</b>			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)  
(Including transactions referred 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 (Substation 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
TM-1	Various	Various				5
304	Various	Various				6
484	WAPA	Sioux Falls, City of				7
385	WAPA	SDSP				8
304	Various	Various				9
440	WAPA	UND				10
446	BOSWE44G22.8	WPPI-West				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

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)  
(Including transactions referred 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.
		49,709	49,709	1
		15,838	15,838	2
39,344,261			39,344,261	3
142,206,202	62,460,686		204,666,888	4
47,344			47,344	5
4,036,785			4,036,785	6
		186,479	186,479	7
		13,533	13,533	8
6,816,126			6,816,126	9
		61,399	61,399	10
		40,320	40,320	11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
<b>192,450,718</b>	<b>62,460,686</b>	<b>367,278</b>	<b>255,278,682</b>	

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/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 and 304

**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.: 5 Column: d**

Termination date - 12/31/2015

**Schedule Page: 328 Line No.: 7 Column: m**

Facilities charge

**Schedule Page: 328 Line No.: 8 Column: m**

Facilities Charge

**Schedule Page: 328 Line No.: 10 Column: m**

Facilities Charge

**Schedule Page: 328 Line No.: 11 Column: m**

Meter charge

**Schedule Page: 328 Line No.: 19 Column: a**

Revenues from Transmission of Electricity of 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.

**TRANSMISSION OF ELECTRICITY BY ISO/RTOs**

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or “true-ups” for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

**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		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	Basin Electric Pwr Coop	OS					2,400	2,400
2	Central MN Muni Pwr	FNS			1,005,665			1,005,665
3	Dairyland Power	OS					19,311	19,311
4	East River Electric Pwr	OLF			237,476			237,476
5	Great River Energy	FNS			28,012,651			28,012,651
6	McLeod Coop Pwr Assn	OLF			24,598			24,598
7	MISO				102,501,682	46,799,201		149,300,883
8	MMPA	FNS			1,015,947			1,015,947
9	Minnkota Pwr Coop	OLF				20,194	212,333	232,527
10	MRES	FNS			1,893,922			1,893,922
11	NWEC	FNS			643,526			643,526
12	Otter Tail Pwr Co	LFP					143,308	143,308
13	SMMPA	FNS			10,802,545			10,802,545
14	SPP	FNS			61,919	296		62,215
15	Stearns Coop Electric	OLF				516	2,796	3,312
16	Accrued Liability						494,240	494,240
	<b>TOTAL</b>				146,199,931	46,820,207	874,388	193,894,526

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
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.: 4 Column: b**

Termination date - 10/31/2017

**Schedule Page: 332 Line No.: 6 Column: b**

Two year notification required for termination

**Schedule Page: 332 Line No.: 7 Column: b**

LFP, FNS, FNO

**Schedule Page: 332 Line No.: 7 Column: f**

MISO Schedule 26-A expense & MISO Admin FERC fee

**Schedule Page: 332 Line No.: 9 Column: b**

Four year notification required for termination

**Schedule Page: 332 Line No.: 12 Column: g**

Interconnection Upgrade fixed charge

**Schedule Page: 332 Line No.: 15 Column: b**

Two year notification required for termination

**Schedule Page: 332 Line No.: 15 Column: g**

Fixed Facility Charge

**Schedule Page: 332 Line No.: 16 Column: g**

Represents amounts accrued related to FERC Docket No. ER15-277 in which Rochester Public Utilities ("RPU"), a Minnesota municipal utility, seeks to collect an annual transmission revenue requirement ("ATRR") from Midcontinent Independent System Operator, Inc. ("MISO") transmission customers in Zone 16, the NSP pricing zone. It is NSP-Minnesota's position that the RPU ATRR should be excluded from Zone 16 and borne by RPU. RPU's Zone 16 rate was conditionally accepted by FERC, subject to refund and hearing procedures, and went into effect January 1, 2016. RPU is not, however, a party to the Joint Pricing Zone Revenue Allocation Agreement ("JPZ Agreement") governing the distribution of the MISO transmission revenues in Zone 16. As a result, revenues collected for the portion of the Zone 16 rate related to RPU's ATRR were distributed to the parties to the JPZ Agreement, including NSP-Minnesota (but excluding RPU), as required by that agreement. NSP-Minnesota has therefore accrued for the eventual distribution of such funds either back to Zone 16 transmission customers or to RPU pending the resolution of Docket No. ER15-277.

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,864,007
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	337,770
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < \$5,000	
6	Director Fees and Expenses	1,076,006
7	SEC Filing Expenses	37,266
8	Other	606
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	3,315,655

**DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)**  
(Except amortization of acquisition 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			30,657,950		30,657,950
2	Steam Production Plant	83,454,951	-11,563,316		-1,131,404	70,760,231
3	Nuclear Production Plant	123,710,333	39,241,381			162,951,714
4	Hydraulic Production Plant-Conventional	1,342,656			-64,441	1,278,215
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	95,029,106	2,443,774	166,150	-2,399,151	95,239,879
7	Transmission Plant	64,708,997	5,255		-1,458,346	63,255,906
8	Distribution Plant	107,208,875	48,770			107,257,645
9	Regional Transmission and Market Operation					
10	General Plant	21,157,752			-852	21,156,900
11	Common Plant-Electric	24,573,798	-53,036	20,654,068		45,174,830
12	<b>TOTAL</b>	521,186,468	30,122,828	51,478,168	-5,054,194	597,733,270

**B. Basis for Amortization Charges**

**ACCOUNT 404**  
Column (d) Computer software is amortized over its expected useful life of 3, 5, 7, 10 and 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

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	8,498					
14	311	288,377		-10.40	2.26		12.20
15	312	1,416,081		-10.50	3.90		13.50
16	314	300,529		-10.40	4.47		12.30
17	315	183,415		-9.30	3.72		14.30
18	316	53,965		-8.80	2.71		14.00
19	317	19,855					
20	SUBTOTAL	2,270,720					
21							
22	Nuclear Production						
23	320	1,459					
24	321	514,195			2.75		15.40
25	322	1,548,870			3.54		16.00
26	323	588,821			4.20		14.80
27	324	457,184			3.53		14.70
28	325	202,128			2.96		15.60
29	326	482,671					
30	SUBTOTAL	3,795,328					
31							
32	Hydro Production						
33	330	1,693					
34	331	1,388		-25.90	4.76		17.20
35	332	10,699		-22.40	4.78		15.00
36	333	10,039		-26.40	5.78		17.20
37	334	3,257		-26.40	5.63		17.20
38	335	61		-26.40	1.03		17.20
39	337						
40	SUBTOTAL	27,137					
41							
42	Other Production						
43	340	20,912			3.44		25.60
44	341	254,784		-8.30	3.16		24.10
45	342	84,455		-5.90	2.64		27.80
46	344	2,044,778		-8.80	3.96		21.60
47	345	259,967		-8.40	3.52		23.50
48	346	31,306		-9.50	2.07		23.00
49	347	68,966					
50	348	4,129			7.14		7.00

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	SUBTOTAL	2,769,297					
13							
14	Transmission						
15	350	150,476					
16	352	91,035	68.00		1.47	R5	
17	353	1,162,791	56.00	-10.00	1.96	R2	
18	354	118,569	70.00	-35.00	1.93	R4	
19	355	1,283,073	62.00	-35.00	2.18	R2	
20	356	520,089	63.00	-30.00	2.06	R1	
21	357	25,779	73.00		1.37	R4	
22	358	30,831	55.00		1.82	R2	
23	359.1	173					
24	SUBTOTAL	3,382,816					
25							
26	Distribution						
27	360	16,463					
28	361	47,646	60.00	-30.00	2.17	R3	
29	362	604,155	55.00	-20.00	2.18	R1.5	
30	364	381,678	44.00	-100.00	4.55	R1	
31	365	427,905	39.00	-20.00	3.08	L0	
32	366	273,682	52.00	-10.00	2.12	R3	
33	367	1,089,853	45.00		2.22	R2.5	
34	368	415,025	32.00	-5.00	3.28		
35	368	20,495	25.00	-10.00	4.40		
36	369	81,725	40.00	-70.00	4.25	R1.5	
37	369	211,324	41.00	-5.00	2.56	R4	
38	370	110,916	15.00		6.67		
39	371	19,791					
40	371	1,635					
41	371	1,280					
42	373	65,430	29.00	-35.00	4.66	L0	
43	374	3,770					
44	SUBTOTAL	3,772,773					
45							
46	General						
47	389	4,439					
48	390	63,450	57.00	-20.00	2.11	R1.5	
49	391	26,489	20.00		5.00		
50	391	28,233	4.00		25.00		

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	847	10.00		10.00		
13	392	32,339	12.00		8.33		
14	392	17,611	15.00		6.67		
15	392	96,452	14.00		7.14		
16	393	1,686	20.00		5.00		
17	394	79,192	15.00		6.67		
18	395	3,374	10.00		10.00		
19	396	43,613	12.00		8.33		
20	397	16,824	9.00		11.11		
21	397	4,252	9.00		11.11		
22	397	35,333	15.00		6.67		
23	397	7,072	15.00		6.67		
24	398	2,795	15.00		6.67		
25	SUBTOTAL	464,001					
26							
27	TOTAL	16,482,072					
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							
49							
50							

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

**Schedule Page: 336 Line No.: 1 Column: d**

Intangible Plant	\$ 18,079,803
Nuclear Production Plant	12,471,319
Hydraulic Production Plant-Conventional	106,828
	\$ 30,657,950

**Schedule Page: 336 Line No.: 7 Column: b**

Transmission Serving Production	\$ 1,087,815
---------------------------------	--------------

**Schedule Page: 336 Line No.: 8 Column: b**

Distribution Serving Production	\$ 76,904
---------------------------------	-----------

**Schedule Page: 336.1 Line No.: 34 Column: a**

Line Transformers

**Schedule Page: 336.1 Line No.: 35 Column: a**

Line Capacitors

**Schedule Page: 336.1 Line No.: 36 Column: a**

Overhead Services

**Schedule Page: 336.1 Line No.: 37 Column: a**

Underground Services

**Schedule Page: 336.1 Line No.: 39 Column: a**

Installation on Customer Premises (Minnesota)

**Schedule Page: 336.1 Line No.: 40 Column: a**

Installation on Customer Premises (South Dakota)

**Schedule Page: 336.1 Line No.: 41 Column: a**

Installation on Customer Premises (North Dakota)

**Schedule Page: 336.1 Line No.: 49 Column: a**

Office Furniture and Equipment

**Schedule Page: 336.1 Line No.: 50 Column: a**

Network Equipment

**Schedule Page: 336.2 Line No.: 12 Column: a**

Transportation Equipment - Automobiles

**Schedule Page: 336.2 Line No.: 13 Column: a**

Transportation Equipment - Light Trucks

**Schedule Page: 336.2 Line No.: 14 Column: a**

Transportation Equipment - Trailers

**Schedule Page: 336.2 Line No.: 15 Column: a**

Transportation Equipment - Heavy Trucks

**Schedule Page: 336.2 Line No.: 19 Column: a**

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	\$ 10,636,115	\$ 147,249,000
396 Power Operated Equipment	3,667,849	43,613,000
Total	\$ 14,303,964	\$ 190,862,000

**Schedule Page: 336.2 Line No.: 20 Column: a**

Communication Equipment

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

**Schedule Page: 336.2 Line No.: 21 Column: a**

Communication Equipment - Two Way

**Schedule Page: 336.2 Line No.: 22 Column: a**

Communication Equipment - EMS

**Schedule Page: 336.2 Line No.: 23 Column: a**

Communication Equipment - AMR

**Schedule Page: 336.2 Line No.: 27 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.

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

**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 DEPARTMENT OF COMMERCE				
2	Assessments	2,075,045		2,075,045	
3	Assessments	368,515		368,515	
4					
5	MINNESOTA PUBLIC UTILITIES COMMISSION				
6	GR13-754 Monticello Prudence Review		443	443	
7	GR13-868 2014 Retail Rate Case		-23,415	-23,415	
8	GR15-826 2016 Retail Rate Case		2,453,084	2,453,084	
9	Assessments	2,841,098		2,841,098	
10	Assessments	319,897		319,897	
11					
12	NORTH DAKOTA PUBLIC SERVICE COMMISSION				
13	PU10-657 2010 Retail Rate Case		53,106	53,106	
14	PU12-813 2012 Retail Rate Case		154,517	154,517	
15	Assessments	-639,916		-639,916	
16	Assessments	1,000		1,000	
17					
18	SOUTH DAKOTA PUBLIC UTILITIES COMMISSION				
19	EL14-058 2014 Retail Rate Case		119,193	119,193	
20	Assessments	285,725		285,725	
21					
22	Other				
23	Mandated inserts		20,248	20,248	
24	Mandated inserts		77	77	
25	Miscellaneous		409,467	409,467	
26	Miscellaneous		39,414	39,414	
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	5,251,364	3,226,134	8,477,498	

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			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Department (f)	Account No. (g)	Amount (h)					
							1
Electric	928	2,075,045					2
Gas	928	368,515					3
							4
							5
Electric	928	443					6
Electric	928	-23,415					7
Electric	928	2,453,084		186	1,113,333		8
Electric	928	2,841,098					9
Gas	928	319,897					10
							11
							12
Electric	928	53,106		186	53,106		13
Electric	928	154,517		186	154,500		14
Electric	928	-639,916					15
Gas	928	1,000					16
							17
							18
Electric	928	119,193		186	119,193		19
Electric	928	285,725					20
							21
							22
Electric	928	20,248					23
Gas	928	77					24
Electric	928	409,467					25
Gas	928	39,414					26
							27
							28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		8,477,498			1,440,132		46

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

**Schedule Page: 350 Line No.: 8 Column: k**  
GR15-826 - 36 month amortization period ending Dec. 31, 2018.

**Schedule Page: 350 Line No.: 13 Column: k**  
PU10-657 - 48 month amortization period ending Dec. 31, 2016. The amortization period was extended as part of PU-12-813.

**Schedule Page: 350 Line No.: 14 Column: k**  
PU12-813 - 48 month amortization period ending Dec. 31, 2016.

**Schedule Page: 350 Line No.: 19 Column: k**  
PU14-058 - 36 month amortization period ending Dec. 31, 2017.

**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: | a. Overhead  |
| (1) Generation                             | b. Underground   |
| a. hydroelectric                           | (3) Distribution   |
| i. Recreation fish and wildlife            | (4) Regional Transmission and Market Operation   |
| ii Other hydroelectric                     | (5) Environment (other than equipment)   |
| b. Fossil-fuel steam                       | (6) Other (Classify and include items in excess of \$50,000.)                                    |
| c. Internal combustion or gas turbine      | (7) Total Cost Incurred  |
| d. Nuclear                                 | B. Electric, R, D & D Performed Externally:  |
| e. Unconventional generation               | (1) Research Support to the electrical Research Council or the Electric Power Research Institute |
| f. Siting and heat rejection               |  |
| (2) Transmission                           |  |

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		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		

**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)		
	4,276,588	Various	4,276,588		1
					2
	931,246	Various	931,246		3
					4
	5,491,849	253	5,491,849		5
					6
	10,699,683		10,699,683		7
					8
					9
					10
					11
					12
					13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
					37
					38

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

**Schedule Page: 352 Line No.: 1 Column: e**

Accounts charged:

107	\$89,837
517	3,599,364
581	2,588
921	58,504
930.2	526,295
	\$4,276,588

**Schedule Page: 352 Line No.: 3 Column: e**

Accounts charged:

182.3	\$10,000
426.1	45,856
426.4	115,230
908	5,000
930.2	755,160
	\$931,246

**Schedule Page: 352 Line No.: 5 Column: b**

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

Research Projects

University of St. Thomas	\$1,438,144
University of Minnesota-Dairy	305,459
University of Minnesota-VWS	270,159
University of Minnesota-Noise	78,087
Minnesota West Community & Tech College	2,400,000
University of Minnesota	1,000,000
	\$5,491,849





Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report End of <u>2016/Q4</u>
---	---	--	--

COMMON UTILITY PLANT AND EXPENSES

- Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
- Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
- Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
- Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Instruction 1:

Account -----	Allocated to Utility Departments		Cost at Dec. 31, 2016 -----
	Electric -----	Gas -----	
COMMON UTILITY PLANT IN SERVICE AND COMPLETED NOT CLASSIFIED			
301 Organization	\$86,141	\$14,467	\$100,608
303 Computer Software	324,345,812	54,474,338	378,820,150
	-----	-----	-----
Total intangible plant	\$324,431,953	\$54,488,805	\$378,920,758
389 Land and land rights	\$5,716,381	\$480,527	\$6,196,908
390 Structures and improvements	157,115,510	13,207,345	170,322,855
391 Office furniture and equipment	117,694,190	9,893,535	127,587,725
392 Transportation equipment	9,968,085	891,979	10,860,064
393 Stores equipment	227,074	19,088	246,162
394 Tools/shop/garage equipment	3,728,302	313,406	4,041,708
395 Laboratory equipment	-	-	-
396 Power operated equipment	911,612	79,300	990,912
397 Communications equipment	958,894	80,606	1,039,500
398 Miscellaneous equipment	537,079	45,148	582,227
399.1 Asset retirement costs for general plant	(1,792,339)	(150,667)	(1,943,006)
	-----	-----	-----
TOTAL	\$619,496,741	\$79,349,072	\$698,845,813

COMMON UTILITY PLANT HELD FOR FUTURE USE

389 Land and Land Rights	\$ -	\$ -	\$ -
--------------------------	------	------	------

COMMON UTILITY PLANT CONSTRUCTION WORK IN PROGRESS

General Plant	\$ 83,943,060	\$12,871,188	\$ 96,814,248
---------------	---------------	--------------	---------------

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report End of <u>2016/Q4</u>
---	---	--	--

COMMON UTILITY PLANT AND EXPENSES

- Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
- Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
- Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
- Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

COMMON UTILITY PLANT ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION

General Plant	\$294,647,842	\$42,753,134	\$337,400,976
---------------	---------------	--------------	---------------

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.

Instruction 2:

DEPARTMENTAL ALLOCATION OF ACCUMULATED PROVISION FOR DEPRECIATION

	"Non-Legal" ARO Balances
	-----
Common General	\$ (7,929,444)
Common Intangible	-
	-----
Total Common	\$ (7,929,444)

Instruction 3:

COMMON UTILITY PLANT EXPENSES

	Electric	Gas	Total
	-----	-----	-----
403 Depreciation Expense	\$24,573,798	\$2,074,456	\$26,648,254
403.1 Depreciation Expense - ARC	(53,036)	(4,460)	(57,496)
404 Amortization of limited term plant	20,654,068	3,647,174	24,301,242
407.4 Amortization of regulatory credits	123,479	10,393	133,872
411.1 Accretion expense	50,156	4,217	54,373
TOTAL	\$45,348,465	\$5,731,780	\$51,080,245

Basis of allocation of Common Utility Plant expenses:

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report End of <u>2016/Q4</u>
---	---	--	--

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.

From	Through	Allocation Methods
403	403	Depreciation allocator (excluding integrated software)
404	404	Software amortization allocator
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.

**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)	19,464,631	35,296,379	68,758,962	76,647,096
9	Net Sales (Account 447)	( 14,763,318)	( 26,173,144)	( 34,936,190)	( 58,082,147)
10	Transmission Rights	( 4,765,255)	( 11,725,206)	( 37,901,499)	( 46,853,432)
11	Ancillary Services	( 163,138)	( 453,692)	( 1,318,439)	( 1,928,489)
12	Other Items (list separately)				
13	Admin Fees	2,159,493	4,357,883	6,610,718	8,969,404
14	Net Purchases for Storage Operations	( 1,774)	( 3,874)	( 235)	3,209
15	ERCOT				
16	Net Purchases (Account 555)	230,664	198,888	207,308	( 356,826)
17	Net Sales (Account 447)				
18	Transmission Rights	( 4,013)	( 4,013)	( 4,013)	( 4,013)
19	Ancillary Services				
20	Other Items				
21	Uplift Charges	29	176	404	586
22	NEISO				
23	Net Purchases (Account 555)				
24	Net Sales (Account 447)				
25	Ancillary Services				
26	Other Items				
27	Admin Fees	2,342	6,079	10,567	15,003
28	Uplift Charges				
29	NYISO				
30	Net Purchases (Account 555)	78,185	145,889	16,212	41,884
31	Transmission Rights				
32	Admin Fees	3,084	3,747	4,542	4,923
33	PJM				
34	Net Purchases (Account 555)	( 7,769)	21,862	48,499	( 82,723)
35	Net Sales (Account 447)				
36	Transmission Rights		8	8	8
37	Ancillary Services				
38	Other Items				
39	Admin Fees	1,349	3,789	7,420	14,957
40	Uplift Charges	605	20,293	46,925	56,913
41	SPP				
42	Net Purchases (Account 555)	( 92)	( 413)	( 277)	8,419
43	Transmission Rights	( 15,692)	( 18,086)	( 18,216)	( 18,216)
44	Uplift Charges	40,505	37,188	37,150	35,434
45	Ancillary Services				155
46	TOTAL	2,259,836	1,713,753	1,569,846	( 21,527,855)



Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/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**

Volume of units is not available.

**Schedule Page: 398 Line No.: 2 Column: b**

Number of units is not available.

**Schedule Page: 398 Line No.: 2 Column: e**

Volume of units is not available.

**Schedule Page: 398 Line No.: 3 Column: b**

Number of units is not available.

**Schedule Page: 398 Line No.: 3 Column: e**

Volume of units is not available.

**Schedule Page: 398 Line No.: 4 Column: b**

Number of units is not available.

**Schedule Page: 398 Line No.: 4 Column: e**

Volume of units is not available.

**Schedule Page: 398 Line No.: 5 Column: b**

Number of units is not available.

**Schedule Page: 398 Line No.: 5 Column: e**

Volume of units is not available.

**Schedule Page: 398 Line No.: 6 Column: b**

Number of units is not available.

**Schedule Page: 398 Line No.: 6 Column: e**

Volume of units is not available.

**Schedule Page: 398 Line No.: 7 Column: b**

Number of units is not available.

**Schedule Page: 398 Line No.: 7 Column: e**

Volume of units is not available.

**Schedule Page: 398 Line No.: 7 Column: g**

NSPM MISO NSPP DA_RC_AMT	\$	84,671
NSPM MISO NSPP RT_RC_AMT		7,955
	\$	<u>92,627</u>

**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	7,397	18	1800	6,147	650	502			
2	February	7,161	8	1900	5,929	631	502			
3	March	6,569	1	1100	5,464	591	502			
4	Total for Quarter 1				17,540	1,872	1,506			
5	April	6,623	18	1400	5,594	544	502			
6	May	7,772	24	1700	6,475	639	502			
7	June	9,086	10	1500	7,513	736	502			
8	Total for Quarter 2				19,582	1,919	1,506			
9	July	10,357	20	1700	8,581	838	502			
10	August	10,209	10	1600	8,510	814	502			
11	September	7,818	6	1600	6,531	660	502			
12	Total for Quarter 3				23,622	2,312	1,506			
13	October	6,747	3	1400	5,643	558	502			
14	November	6,758	30	1800	5,601	556	502			
15	December	7,592	14	1800	6,311	666	502			
16	Total for Quarter 4				17,555	1,780	1,506			
17	Total Year to Date/Year				78,299	7,883	6,024			

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
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:

January	334
February	301
March	302
April	262
May	289
June	258
July	294
August	301
September	312
October	244
November	262
December	349
	3,508

"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:

January	68
February	51
March	53
April	46
May	53
June	48
July	89
August	75
September	48
October	49
November	58
December	67
	705

**Schedule Page: 400 Line No.: 1 Column: f**

"Firm Network Service - For Others" does not include the load of Great River Energy (GRE), Southern Minnesota Municipal Power Agency (SMMPA), or Missouri River Energy Services (MRES) city of Marshall Load in the NSP Companies' Midcontinent ISO Pricing Zone. The GRE, SMMPA and MRES city of Marshall network load not included in column (f) is:

GRE	SMMPA	MRES
-----	-------	------

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

January	689	119	77
February	712	119	76
March	578	114	71
April	534	108	69
May	715	130	75
June	875	152	80
July	990	161	85
August	942	166	84
September	667	135	77
October	556	117	73
November	635	110	73
December	711	122	80
	8,604	1,553	920

Name of Respondent  
Northern States Power Company (Minnesota)

This Report Is:  
(1)  An Original  
(2)  A Resubmission

Date of Report  
(Mo, Da, Yr)  
04/10/2017

Year/Period of Report  
End of 2016/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	Monthly Peak MW - Total	Day of Monthly Peak	Hour of Monthly Peak	Imports into ISO/RTO	Exports from ISO/RTO	Through and Out Service	Network Service Usage	Point-to-Point Service Usage	Total Usage
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(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									

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)	34,621,919
3	Steam	12,949,579	23	Requirements Sales for Resale (See instruction 4, page 311.)	5,922,958
4	Nuclear	13,860,816	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	6,897,102
5	Hydro-Conventional	93,578	25	Energy Furnished Without Charge	278
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	48,463
7	Other	8,527,001	27	Total Energy Losses	1,143,438
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	48,634,158
9	Net Generation (Enter Total of lines 3 through 8)	35,430,974			
10	Purchases	13,203,184			
11	Power Exchanges:				
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)	48,634,158			

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report End of <u>2016/Q4</u>
---	---	--	--

**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-Requirements Sales for Resale & Associated Losses (c)	MONTHLY PEAK		
				Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	4,127,523	454,855	5,385	18	1900
30	February	3,732,241	430,225	5,196	8	1900
31	March	3,824,052	553,685	4,778	1	1100
32	April	3,878,259	823,938	4,904	18	1400
33	May	3,773,014	555,013	5,769	24	1700
34	June	4,054,659	396,347	6,713	10	1500
35	July	4,589,861	405,930	7,680	20	1700
36	August	4,573,106	468,383	7,576	3	1800
37	September	3,916,031	556,305	5,728	6	1700
38	October	3,882,698	730,543	4,997	3	1400
39	November	3,854,044	722,912	4,953	30	1800
40	December	4,428,670	798,966	5,523	14	1800
41	TOTAL	48,634,158	6,897,102			

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

**Schedule Page: 401 Line No.: 10 Column: b**

Includes 676 MWH purchased for energy storage operation.

**Schedule Page: 401 Line No.: 27 Column: b**

MWH stored in Wind2Battery project on Dec. 31, 2016 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.

Day	Hour	Northern States Power Co. (a Minnesota corporation)			Northern States Power Co. (a Wisconsin corporation)		
		Integrated System	Minnesota	North Dakota	South Dakota	Wisconsin	
18-Jan	1900	6,507	4,664	398	323	1,095	27
8-Feb	1900	6,258	4,522	373	301	1,037	25
1-Mar	1100	5,761	4,172	332	274	960	23
18-Apr	1400	5,829	4,346	288	270	905	20
24-May	1700	6,766	5,083	340	346	977	20
10-Jun	1500	7,869	5,874	381	458	1,134	22
20-Jul	1700	9,002	6,750	433	497	1,298	24
3-Aug	1800	8,904	6,691	425	460	1,304	24
6-Sep	1700	6,821	5,248	309	171	1,066	27
3-Oct	1400	5,939	4,392	304	301	930	12
30-Nov	1800	5,914	4,328	325	300	940	21
14-Dec	1800	6,646	4,784	405	334	1,098	25

**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: <i>Riverside</i> (b)	Plant Name: <i>Wilmarth</i> (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)	515				20	
7	Plant Hours Connected to Load	6116				7849	
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	25				27	
12	Net Generation, Exclusive of Plant Use - KWh	2432580177				102710075	
13	Cost of Plant: Land and Land Rights	450132				499773	
14	Structures and Improvements	52226101				8063468	
15	Equipment Costs	259887622				45362147	
16	Asset Retirement Costs	864346				962921	
17	Total Cost	313428201				54888309	
18	Cost per KW of Installed Capacity (line 17/5) Including	534.9517				2195.5324	
19	Production Expenses: Oper, Supv, & Engr	402745				192937	
20	Fuel	60967897				482954	
21	Coolants and Water (Nuclear Plants Only)	0				0	
22	Steam Expenses	7632				1608798	
23	Steam From Other Sources	0				0	
24	Steam Transferred (Cr)	0				0	
25	Electric Expenses	2108589				144071	
26	Misc Steam (or Nuclear) Power Expenses	801207				806181	
27	Rents	556267				199835	
28	Allowances	0				0	
29	Maintenance Supervision and Engineering	219150				59961	
30	Maintenance of Structures	1465180				135202	
31	Maintenance of Boiler (or reactor) Plant	3062				1755638	
32	Maintenance of Electric Plant	2750484				665988	
33	Maintenance of Misc Steam (or Nuclear) Plant	325659				870712	
34	Total Production Expenses	69607872				6922277	
35	Expenses per Net KWh	0.0286				0.0674	
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	16490194	14	177689	30206	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	1055	137694	6052	1059	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	3.697	58.988	2.015	4.923	0.000
41	Average Cost of Fuel per Unit Burned	0.000	3.697	58.988	14.036	4.923	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	3.503	10.200	1.160	4.650	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.025	0.000	0.000	0.030	0.000
44	Average BTU per KWh Net Generation	0.000	7019.670	0.000	0.000	21250.630	0.000

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: <u>Sherburne County</u> (b)	Plant Name: <u>Granite City</u> (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)	2469.32	72.00				
6	Net Peak Demand on Plant - MW (60 minutes)	1901	30				
7	Plant Hours Connected to Load	8784	24				
8	Net Continuous Plant Capability (Megawatts)	1879	64				
9	When Not Limited by Condenser Water	1879	64				
10	When Limited by Condenser Water	1879	52				
11	Average Number of Employees	253	0				
12	Net Generation, Exclusive of Plant Use - KWh	10002378056	-232680				
13	Cost of Plant: Land and Land Rights	5951721	40240				
14	Structures and Improvements	225182051	1241718				
15	Equipment Costs	1197199512	7525213				
16	Asset Retirement Costs	175096	68958				
17	Total Cost	1428508380	8876129				
18	Cost per KW of Installed Capacity (line 17/5) Including	578.5027	123.2796				
19	Production Expenses: Oper, Supv, & Engr	2673757	0				
20	Fuel	229343171	66943				
21	Coolants and Water (Nuclear Plants Only)	0	0				
22	Steam Expenses	7911450	0				
23	Steam From Other Sources	0	0				
24	Steam Transferred (Cr)	0	0				
25	Electric Expenses	3227986	29056				
26	Misc Steam (or Nuclear) Power Expenses	13041035	857542				
27	Rents	2034967	4650				
28	Allowances	0	0				
29	Maintenance Supervision and Engineering	1977489	7276				
30	Maintenance of Structures	2741879	29150				
31	Maintenance of Boiler (or reactor) Plant	19206440	0				
32	Maintenance of Electric Plant	6283369	7546				
33	Maintenance of Misc Steam (or Nuclear) Plant	9690072	0				
34	Total Production Expenses	298131615	1002163				
35	Expenses per Net KWh	0.0298	-4.3070				
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	5907571	0	15053	3083	0	781
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	8700	0	141959	1000	0	138963
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	36.198	0.000	63.913	4.890	0.000	66.374
41	Average Cost of Fuel per Unit Burned	37.346	0.000	63.913	4.890	0.000	66.374
42	Average Cost of Fuel Burned per Million BTU	2.146	0.000	10.720	4.890	0.000	11.372
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.020	0.000	0.000	-0.290	0.000
44	Average BTU per KWh Net Generation	0.000	10285.180	0.000	0.000	-32805.840	0.000



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
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000

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: <i>A S King</i> (d)	Plant Name: <i>Prairie Island</i> (e)	Plant Name: <i>Blue Lake</i> (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						
541	1114	454	6						
6290	8784	883	7						
511	1092	545	8						
511	1092	545	9						
511	1040	0	10						
86	673	5	11						
2715572900	8263058000	197208000	12						
1335100	969229	141878	13						
38620988	313268814	1623647	14						
661536103	1660717974	94471040	15						
3833412	174529690	94817	16						
705325603	2149485707	96331382	17						
1178.6858	1812.0770	172.2295	18						
690548	44643743	120484	19						
62484824	72011347	8114997	20						
0	4758389	0	21						
6176628	27159670	0	22						
0	0	0	23						
0	0	0	24						
804896	4147206	265490	25						
3245828	79621338	45136	26						
970170	6261808	55992	27						
0	0	0	28						
410950	4109342	37342	29						
2499401	845272	187072	30						
8981609	29158695	0	31						
2944859	11683767	554663	32						
3259211	23142866	4403	33						
92468924	307543443	9385579	34						
0.0341	0.0372	0.0476	35						
Coal	Gas	Oil		Nuclear		Gas		Oil	36
Tons	MCF	Barrels		Grams: U235		MCF		Barrels	37
1522701	66138	114	0	802864	0	1996559	0	3117	38
8874	1056	138333	0	108747	0	1062	0	138011	39
38.286	3.923	81.999	0.000	0.000	0.000	3.909	0.000	99.782	40
41.700	3.923	81.999	0.000	0.000	0.000	3.909	0.000	99.782	41
2.349	3.715	14.113	0.000	0.829	0.000	3.680	0.000	17.214	42
0.000	0.020	0.000	0.000	0.010	0.000	0.000	0.040	0.000	43
0.000	9978.140	0.000	0.000	10566.610	0.000	0.000	10845.400	0.000	44

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: <i>Inver Hills</i> (d)	Plant Name: <i>High Bridge 7, 8, 9</i> (e)	Plant Name: <i>Monticello</i> (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						
269	629	670	6						
265	5358	8784	7						
371	606	646	8						
371	606	646	9						
282	530	617	10						
7	23	525	11						
17435963	2125527000	5597758000	12						
432561	528150	783302	13						
1417386	70897135	218109485	14						
57422832	316687477	1168306394	15						
114211	19394	308141112	16						
59386990	388132156	1695340293	17						
211.7183	602.6335	2475.0577	18						
7711	367189	27071298	19						
1068557	46889426	44970200	20						
0	0	3915850	21						
0	0	20643952	22						
0	0	0	23						
0	0	0	24						
243094	2559186	0	25						
89427	1260663	58437989	26						
47365	492128	4501658	27						
0	0	0	28						
557	155542	2537807	29						
365521	775140	0	30						
0	2176	13414210	31						
446669	1190708	5807646	32						
13863	202025	7757243	33						
2282764	53894183	189057853	34						
0.1309	0.0254	0.0338	35						
	Gas	Oil	Nuclear	36					
	MCF	Barrels	Grams: U235	37					
0	287376	587	494195	0	38				
0	1058	139856	118507	0	39				
0.000	3.560	77.844	0.000	0.000	0.000	40			
0.000	3.560	85.399	0.000	0.000	0.000	41			
0.000	3.364	14.539	0.000	0.000	0.772	0.000	42		
0.000	0.060	0.000	0.000	0.020	0.000	0.010	0.000	43	
0.000	17639.110	0.000	0.000	7019.670	0.000	0.000	10462.450	0.000	44

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: <i>Black Dog 3 &amp; 4</i> (d)	Plant Name: <i>Key City</i> (e)	Plant Name: (f)	Line No.						
Steam	Gas Turbine		1						
Conventional	Ind Enclosures		2						
1952	1970		3						
1960	1970		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	-32640	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						
360962	0	0	19						
4107	0	0	20						
0	0	0	21						
2807502	0	0	22						
0	0	0	23						
0	0	0	24						
563819	6	0	25						
618949	0	0	26						
245052	442	0	27						
0	0	0	28						
19120	0	0	29						
1241765	1039	0	30						
341685	0	0	31						
131838	3199	0	32						
995629	0	0	33						
7330428	4686	0	34						
0.0000	-0.1436	0.0000	35						
	Oil		36						
	Barrels		37						
0	47	0	0	0	0	0	0	0	38
0	139898	0	0	0	0	0	0	0	39
0.000	88.013	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	88.013	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	14.979	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.310	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	7410.810	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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	38
0	0	0	39
0.000	0.000	0.000	40
0.000	0.000	0.000	41
0.000	0.000	0.000	42
0.000	0.000	0.000	43
0.000	0.000	0.000	44

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
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 UO2 contained in zirconium alloy based cladding. The equilibrium cycle has approximately 47 metric tons of uranium metal with a nominal U-235 enrichment of 4.95 weight percent in the fresh fuel. The reactor is licensed to operate at 1677 MWt.

**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 UO2 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: 402 Line No.: 39 Column: b1**

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

- Coal: Btu/pound
- Oil: Btu/gallon
- Gas: Btu/cubic ft

**Schedule Page: 402 Line No.: 39 Column: e2**

Average heat content of fuel burned is MBTU/kg U235.

**Schedule Page: 402.1 Line No.: 39 Column: f2**

Average heat content of fuel burned is in KBTU/gm U235.

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. 2056 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	8,680	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	93,577,886	0
13	Cost of Plant		
14	Land and Land Rights	1,548,707	0
15	Structures and Improvements	1,349,723	0
16	Reservoirs, Dams, and Waterways	8,537,091	0
17	Equipment Costs	13,356,793	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	24,792,314	0
21	Cost per KW of Installed Capacity (line 20 / 5)	1,784.9038	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	2,201	0
24	Water for Power	0	0
25	Hydraulic Expenses	663	0
26	Electric Expenses	206,041	0
27	Misc Hydraulic Power Generation Expenses	147,274	0
28	Rents	23,244	0
29	Maintenance Supervision and Engineering	25,154	0
30	Maintenance of Structures	86,278	0
31	Maintenance of Reservoirs, Dams, and Waterways	45,098	0
32	Maintenance of Electric Plant	31,618	0
33	Maintenance of Misc Hydraulic Plant	7,970	0
34	Total Production Expenses (total 23 thru 33)	575,541	0
35	Expenses per net KWh	0.0062	0.0000

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



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. Plant Name: <span style="float: right;">(c)</span>	0	FERC Licensed Project No. Plant Name: <span style="float: right;">(d)</span>	0	FERC Licensed Project No. Plant Name: <span style="float: right;">(e)</span>	0	Line No.
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38

**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 PLANT					
2						
3	Red Wing	1949	23.00	22.0	128,918,207	62,975,892
4	Minnesota Valley	1932				13,507,340
5	High Bridge 5 & 6	1924				
6						
7						
8	GAS PLANT					
9						
10	West Faribault	1965				
11						
12						
13	INTERNAL COMBUSTION					
14						
15	Dispersed Generation				-195,200	2,505,564
16						
17						
18	WIND TURBINE PLANTS					
19						
20	Lake Benton	1997				10,190,362
21	Grand Meadow Wind Farm	2008	100.50	100.0	311,438,295	220,543,388
22	Nobles Wind	2010	201.00	201.0	721,615,728	536,933,164
23	Pleasant Valley	2015	200.00	194.0	802,870,055	353,432,557
24	Borders Wind	2015	150.00	147.0	622,225,798	272,067,736
25	Courtenay Wind	2016	200.00	197.6	86,382,029	297,469,987
26						
27	SOLAR					
28						
29	Photovoltaic Units	1995				306,139
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						

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		Kind of Fuel (k)	Fuel Costs (in cents per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
						2
2,738,082	2,477,849	472,069	3,308,327	RDF, Gas	111	3
	769		32,451			4
	54,066		12,800			5
						6
						7
						8
						9
						10
						11
						12
						13
						14
	16	11,790	61,405	Oil	1,675	15
						16
						17
						18
						19
				Wind		20
2,194,462	1,343,417		1,256,011	Wind		21
2,671,309	2,408,976		1,209,132	Wind		22
1,767,163	3,331,959		3,644,824	Wind		23
1,813,785	2,373,512		2,144,477	Wind		24
						25
						26
						27
						28
				Solar		29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42
						43
						44
						45
						46

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/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)

**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		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	(5702)FORBES	RIEL	500.00	500.00	TOWER	203.78		1
2	(5703)CHISAGO CO	FORBES	500.00	500.00	TOWER	61.45		1
3	(0953)SPLIT ROCK	LAKEFIELD JCT	345.00	345.00	SINGLE POLE	22.67		1
4			345.00	345.00	SINGLE POLE	4.43		1
5			345.00	345.00	SINGLE POLE	60.85		1
6			345.00	345.00	TOWER	0.22		1
7	(0954)ALEXANDRIA	QUARRY	345.00	345.00	2 POLE	17.33		1
8			345.00	345.00	SINGLE POLE	63.89		1
9	(0955)ALEXANDRIA	BISON	345.00	345.00	2 POLE	6.53		1
10			345.00	345.00	SINGLE POLE	132.25		1
11	(0956)CEDAR MOUNTAIN	LYON CO	345.00	345.00	SINGLE POLE	49.49		1
12	(0957)CEDAR MOUNTAIN	LYON CO	345.00	345.00	SINGLE POLE		49.49	1
13	(0958)CEDAR MOUNTAIN	HELENA	345.00	345.00	SINGLE POLE	73.10		1
14	(0959)CEDAR MOUNTAIN	HELENA	345.00	345.00	SINGLE POLE		73.06	1
15	(0960)CHUB LAKE	HELENA	345.00	345.00	SINGLE POLE	20.87		1
16	(0961)CHUB LAKE	HAMPTON	345.00	345.00	SINGLE POLE	18.10		1
17	(0962)HAZEL CREEK	LYON CO	345.00	345.00	SINGLE POLE	24.54		1
18	(0964)HAMPTON	NORTH ROCHESTER	345.00	345.00	SINGLE POLE	37.85		1
19	(0965)BRIGGS ROAD	NORTH ROCHESTER	345.00	345.00	2 POLE	3.12		1
20			345.00	345.00	3 POLE	1.70		1
21			345.00	345.00	SINGLE POLE	38.54		1
22	(0970)BROOKINGS CO	WHITE	345.00	345.00	SINGLE POLE	0.38		1
23	(0971)BROOKINGS CO	WHITE	345.00	345.00	SINGLE POLE	0.42		1
24	(0972)BROOKINGS CO	LYON CO	345.00	345.00	SINGLE POLE	59.30		1
25	(0973)MONTICELLO	QUARRY	345.00	345.00	SINGLE POLE	30.04		1
26	(0974)MANKATO ENERGY	WILMARTH	345.00	345.00	SINGLE POLE	0.22		1
27	(0975)A.S. KING	RED ROCK	345.00	345.00	K-FRAME	3.54		1
28			345.00	345.00	TOWER	21.80		1
29	(0976)PARKERS LAKE	PRAIRIE ISLAND	345.00	345.00	K-FRAME	21.11		1
30			345.00	345.00	K-FRAME	6.16		1
31			345.00	345.00	SINGLE POLE	5.45		1
32			345.00	345.00	TOWER	34.87		1
33	(0977)A.S. KING	TERMINAL	345.00	345.00	SINGLE POLE	2.82		1
34			345.00	345.00	TOWER	20.00		1
35	(0978)MONTICELLO	PARKERS LAKE	345.00	345.00	H-FRAME	16.90		1
36					TOTAL	5,038.00	587.62	126

**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		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1			345.00	345.00	K-FRAME	3.37		1
2			345.00	345.00	SINGLE POLE	0.59		1
3			345.00	345.00	TOWER	16.28		1
4	(0979)PRAIRIE ISLAND	ADAMS	345.00	345.00	H-FRAME	19.62		1
5			345.00	345.00	K-FRAME	54.26		1
6			345.00	345.00	TOWER	2.40		1
7	(0980)CHISAGO CO	COON CREEK	345.00	345.00	SINGLE POLE	4.61	2.82	1
8			345.00	345.00	SINGLE POLE	26.11		1
9			345.00	345.00	TOWER	6.87	11.30	1
10			345.00	345.00	TOWER	5.27	0.55	1
11	(0981)A.S. KING	EAU CLAIRE	345.00	345.00	K-FRAME	3.69		1
12			345.00	345.00	TOWER	0.72	15.19	1
13	(0982)BLUE LAKE	LAKEFIELD JCT	345.00	345.00	2 POLE	0.72		1
14			345.00	345.00	H-FRAME	11.24		1
15			345.00	345.00	K-FRAME	94.83		1
16			345.00	345.00	SINGLE POLE	9.95		1
17			345.00	345.00	TOWER	14.03		1
18	(0984)SHERBURNE CO	TERMINAL	345.00	345.00	K-FRAME	19.79		1
19			345.00	345.00	SINGLE POLE		4.61	1
20			345.00	345.00	SINGLE POLE	14.81		1
21			345.00	345.00	TOWER		9.02	1
22			345.00	345.00	TOWER	8.84		1
23	(0985)SHERBURNE CO	COON CREEK	345.00	345.00	H-FRAME	16.26	1.12	1
24			345.00	345.00	K-FRAME	3.36		1
25			345.00	345.00	SINGLE POLE	0.29	0.51	1
26			345.00	345.00	TOWER	5.79	5.79	1
27	(0986)PRAIRIE ISLAND	RED ROCK	345.00	345.00	K-FRAME	21.23		1
28			345.00	345.00	SINGLE POLE	5.91		1
29			345.00	345.00	TOWER	2.25		1
30			345.00	345.00	TOWER	0.12	2.40	1
31	(0987)PRAIRIE ISLAND	RED ROCK	345.00	345.00	K-FRAME	18.32		1
32			345.00	345.00	SINGLE POLE	2.35	6.50	1
33			345.00	345.00	TOWER		2.25	1
34			345.00	345.00	TOWER	0.15	2.37	1
35	(0988)BLUE LAKE	PARKERS LAKE	345.00	345.00	SINGLE POLE		2.11	1
36					TOTAL	5,038.00	587.62	126

**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		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1			345.00	345.00	TOWER		12.67	1
2	(0989)BLUE LAKE	RED ROCK	345.00	345.00	H-FRAME	0.90		1
3			345.00	345.00	K-FRAME	2.77		1
4			345.00	345.00	SINGLE POLE		0.83	1
5			345.00	345.00	TOWER	9.12	17.16	1
6	(0991)MONTICELLO	SHERBURNE CO	345.00	345.00	TOWER		5.81	1
7	(0992)SHERBURNE CO	COON CREEK	345.00	345.00	K-FRAME	16.93	0.66	1
8			345.00	345.00	SINGLE POLE		14.18	1
9			345.00	345.00	TOWER		11.62	1
10	(0994)A.S. KING	CHISAGO CO	345.00	345.00	SINGLE POLE		26.11	1
11			345.00	345.00	TOWER		5.51	1
12			345.00	345.00	TOWER		1.11	1
13			345.00	345.00	TOWER		5.45	1
14	(0996)DICKINSON	PARKERS LAKE	345.00	345.00	TOWER	0.13	9.62	1
15	(0997)SPLIT ROCK	WHITE	345.00	345.00	SINGLE POLE	4.46		1
16			345.00	345.00	TOWER	0.45	0.24	1
17	(0998)SIOUX CITY	SPLIT ROCK	345.00	345.00	SINGLE POLE		0.63	1
18			345.00	345.00	SINGLE POLE		4.43	1
19	(0900)GRANITE FALLS	BLUE LAKE	230.00	230.00	H-FRAME	1.35		1
20			230.00	230.00	SINGLE POLE	3.36		1
21			230.00	230.00	TOWER	103.04		1
22	(0902)RED ROCK	BEAR CREEK	230.00	230.00	K-FRAME	2.66		1
23			230.00	230.00	SINGLE POLE	63.80		1
24	(0909)AUDUBON	HUBBARD	230.00	230.00	H-FRAME	31.12		1
25			230.00	230.00	SINGLE POLE	7.42		1
26	(0910)MAPLE RIVER	WAHPETON	230.00	230.00	TOWER	3.59		1
27	(0911)MAPLE RIVER	SHEYENNE	230.00	230.00	H-FRAME	4.20		1
28			230.00	230.00	TOWER	0.03	3.72	1
29	(0912)DRAYTON	LETELLIER	230.00	230.00	H-FRAME	28.66		1
30			230.00	230.00	SINGLE POLE	0.07		1
31	(0915)FARGO	SHEYENNE	230.00	230.00	H-FRAME	2.88		1
32			230.00	230.00	TOWER	1.17	0.19	1
33	(0916)GRAND FORKS	PRAIRIE	230.00	230.00	H-FRAME	5.81		1
34			230.00	230.00	SINGLE POLE	1.01		1
35	(0918)SIOUX FALLS	SPLIT ROCK	230.00	230.00	SINGLE POLE	0.96		1
36					TOTAL	5,038.00	587.62	126

**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		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	(0919)PAYNESVILLE TRANS	WILLMAR	230.00	230.00	H-FRAME	2.49		1
2			230.00	230.00	SINGLE POLE	27.24		1
3	(0920)RUGBY	GLENBOROUGH	230.00	230.00	H-FRAME	56.50		1
4			230.00	230.00	SINGLE POLE	0.15		1
5	(0921)RED ROCK	BEAR CREEK	230.00	230.00	SINGLE POLE	10.92	0.09	1
6			230.00	230.00	TOWER	2.78		1
7	(0922)BOSWELL	CASS LAKE	230.00	230.00	SINGLE POLE	51.46		1
8	(0923)WILTON	CASS LAKE	230.00	230.00	SINGLE POLE	19.32		1
9	(0963)HAZEL CREEK	MINNESOTA VALLEY	230.00	345.00	SINGLE POLE	4.97		1
10	(5300)SOUTH BEND	WINNEBAGO	161.00	161.00	H-FRAME	29.46		1
11			161.00	161.00	SINGLE POLE	0.65		1
12	(5301)SPLIT ROCK	ELK	161.00	161.00	H-FRAME	18.67		1
13			161.00	161.00	SINGLE POLE	0.87		1
14			161.00	161.00	SINGLE POLE	0.53		1
15	(5305)LAWRENCE CREEK	ST CROIX FALLS	161.00	161.00	SINGLE POLE	1.57		1
16			161.00	161.00	UNDERGROU	0.58		1
17	(5306)BYRON	PLEASANT VALLEY	161.00	161.00	SINGLE POLE	16.60		1
18	(5309)CHESTER	NORTH ROCHESTER	161.00	161.00	SINGLE POLE	11.41		1
19			161.00	161.00	SINGLE POLE	1.87	14.39	1
20	(5310)NORTH ROCHESTER	NORTHERN HILLS	161.00	161.00	SINGLE POLE	15.12		1
21			161.00	161.00	Y-FRAME	0.39		1
22								
23	Summary of 115 kV System		115.00	115.00	Overhead	1,460.30	134.21	
24			115.00	115.00	Underground	13.22		
25	Summary of 69 kV System		69.00	69.00	Overhead	1,475.03	97.52	
26			69.00	69.00	Underground	1.62		
27	Summary of 34.5 kV System		34.50	34.50	Overhead	60.05	32.38	
28			34.50	34.50	Underground	0.59		
29	All lines							
30								
31								
32								
33								
34								
35								
36					TOTAL	5,038.00	587.62	126

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 (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
9-1192 ACSR 45/7	1,723,334	65,307,062	67,030,396					1
9-1192 ACSR 45/7	2,237,403	15,571,270	17,808,674					2
6-397.5 ACSR 26/7	7,693,156	121,643,804	129,336,959					3
6-954 KCMIL ACSR								4
6-954 ACSS/TW 20/								5
6-954 ACSS/TW 20/								6
6-954ACSS/TW	4,188,381	66,051,104	70,239,485					7
6-954 ACSS/TW 20/								8
6-954 ACSS/TW 20/	7,557,629	106,672,367	114,229,996					9
6-954 ACSS/TW 20/								10
6-954 ACSS/TW 20/	4,706,305	65,839,990	70,546,295					11
6-954 ACSS/TW 20/								12
6-954 ACSS/TW 20/	10,380,378	112,135,762	122,516,140					13
6-954 ACSS/TW 20/								14
6-954 ACSS/TW 20/	6,877,878	36,163,577	43,041,454					15
6-954 ACSS/TW 20/	5,759,895	37,681,201	43,441,096					16
6-954 ACSS/TW 20/	339,775	27,093,463	27,433,238					17
6-397.5	8,295,643	54,839,560	63,135,203					18
6-954 ACSS/TW 20/	5,000,736	60,752,372	65,753,108					19
6-954 ACSS/TW 20/								20
6-954 ACSS/TW 20/								21
6-795 KCMIL ACSS		1,215,849	1,215,849					22
6-795 KCMIL ACSS	13,748	933,240	946,988					23
6-954 KCMIL ACSS/	859,142	77,150,244	78,009,386					24
6-954 KCMIL ACSS/	5,175,862	10,969,295	16,145,156					25
6-795 KCMIL ACSR		888,655	888,655					26
6-795 KCMIL ACSR	401,128	2,587,137	2,988,265					27
6-795 KCMIL ACSR								28
6-795 KCMIL ACSR	2,319,556	12,563,142	14,882,698					29
6-954 KCMIL ACSR								30
6-795 KCMIL ACSR								31
6-795 KCMIL ACSR								32
6-795 KCMIL ACSR	2,273,876	4,469,860	6,743,736					33
6-795 KCMIL ACSR								34
6-954 KCMIL ACSR	882,197	16,151,541	17,033,738					35
	119,338,509	2,020,597,118	2,139,935,626	1,263,292	9,213,075	2,879,927	13,356,294	36

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 (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
6-954 KCMIL ACSR								1
6-954 KCMIL ACSR								2
6-954 KCMIL ACSR								3
6-795 KCMIL ACSR	187,240	23,307,161	23,494,401					4
6-795 KCMIL ACSR								5
6-954 KCMIL ACSR								6
6-795 KCMIL ACSR	5,394,714	13,782,883	19,177,597					7
6-954 KCMIL ACSR								8
6-795 KCMIL ACSR								9
6-954 KCMIL ACSR								10
6-795 KCMIL ACSR	24,099	872,818	896,916					11
6-795 KCMIL ACSR								12
6-795 KCMIL ACSR	1,478,561	25,759,282	27,237,843					13
6-795 KCMIL ACSR								14
6-795 KCMIL ACSR								15
6-795 KCMIL ACSR								16
6-795 KCMIL ACSR								17
6-954 KCMIL ACSR	667,056	9,635,244	10,302,300					18
6-795 KCMIL ACSR								19
6-954 KCMIL ACSR								20
6-795 KCMIL ACSR								21
6-954 KCMIL ACSR								22
6-954 KCMIL ACSR	17,816	15,547,729	15,565,545					23
6-954 KCMIL ACSR								24
6-954 KCMIL ACSR								25
6-954 KCMIL ACSR								26
6-795 KCMIL ACSR	661,692	6,976,971	7,638,662					27
6-795 KCMIL ACSR								28
6-795 KCMIL ACSR								29
6-954 KCMIL ACSR								30
6-795 KCMIL ACSR		2,942,385	2,942,385					31
6-795 KCMIL ACSR								32
6-795 KCMIL ACSR								33
6-954 KCMIL ACSR								34
6-795 KCMIL ACSR		478,209	478,209					35
	119,338,509	2,020,597,118	2,139,935,626	1,263,292	9,213,075	2,879,927	13,356,294	36

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 (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
6-795 KCMIL ACSR								1
6-795 KCMIL ACSR	353,005	3,108,909	3,461,914					2
6-795 KCMIL ACSR								3
6-795 KCMIL ACSR								4
6-795 KCMIL ACSR								5
6-954 KCMIL ACSR		196,978	196,978					6
6-954 KCMIL ACSR	472,775	3,455,294	3,928,069					7
6-954 KCMIL ACSR								8
6-954 KCMIL ACSR								9
6-954 KCMIL ACSR		1,648,291	1,648,291					10
6-795 KCMIL ACSR								11
6-795 KCMIL ACSR								12
6-954 KCMIL ACSR								13
6-954 ACSR 54/7		564,837	564,837					14
6-954 ACSS/TW 20/	139,860	8,455,822	8,595,682					15
6-954 ACSS/TW 20/								16
6-954 KCMIL ACSS/		670,200	670,200					17
6-954 KCMIL ACSS								18
3-795 KCMIL ACSR	437,164	8,094,209	8,531,374					19
3-795 KCMIL ACSR								20
3-795 KCMIL ACSR								21
3-795 KCMIL ACSR	437,738	8,161,304	8,599,043					22
3-795 KCMIL ACSR								23
3-795 KCMIL ACSR	57,863	6,002,680	6,060,544					24
3-795 KCMIL ACSR								25
3-795 KCMIL ACSR	55,625	283,964	339,589					26
3-795 KCMIL ACSR	31,735	834,626	866,361					27
3-795 KCMIL ACSR								28
3-954 KCMIL ACSR	57,281	2,871,019	2,928,301					29
3-954 KCMIL ACSR								30
3-795 KCMIL ACSR	21,223	1,071,447	1,092,670					31
3-795 KCMIL ACSR								32
3-954 KCMIL ACSR	24,662	1,501,259	1,525,920					33
3-954 KCMIL ACSR								34
3-795 KCMIL ACSS	531,676	605,867	1,137,542					35
	119,338,509	2,020,597,118	2,139,935,626	1,263,292	9,213,075	2,879,927	13,356,294	36

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 (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
3-795 KCMIL ACSR	302,577	7,615,686	7,918,263					1
3-795 KCMIL ACSR								2
3-954 KCMIL ACSR	1,288,507	12,636,162	13,924,670					3
3-954 KCMIL ACSR								4
3-1272 ACSR 45/7								5
3-1272 ACSR 45/7								6
3-795 KCMIL ACSS	1,023,124	23,387,110	24,410,234					7
3-795 KCMIL ACSS	884,508	9,194,724	10,079,232					8
6-954 ACSS/TW 20/	355,907	9,162,305	9,518,212					9
3-477 KCMIL ACSR	143,079	1,706,835	1,849,914					10
3-477 KCMIL ACSR								11
3-477 ACSR 26/7	59,271	2,015,147	2,074,419					12
3-2312 KCMIL								13
3-477 KCMIL ACSR								14
3-795 KCMIL ACSS	52,746	9,823,670	9,876,416					15
3000 KCMIL CU								16
3-795 KCMIL ACSS	477,246	6,134,098	6,611,344					17
6-397.5 TACSR 26/	523,196	12,354,325	12,877,521					18
6-954 KCMIL ACSS								19
3-795 KCMIL ACSS	663,115	9,559,256	10,222,370					20
3-795 KCMIL ACSS								21
								22
	19,761,545	625,089,640	644,851,185					23
								24
	5,629,813	219,792,439	225,422,252					25
								26
	436,068	28,615,838	29,051,906					27
								28
				1,263,292	9,213,075	2,879,927	13,356,294	29
								30
								31
								32
								33
								34
								35
	119,338,509	2,020,597,118	2,139,935,626	1,263,292	9,213,075	2,879,927	13,356,294	36

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

**Schedule Page: 422 Line No.: 7 Column: a**

NSM (0954) QUARRY-ALEXANDRIA SWITCHING STATION: Xcel Energy owns 36.1000%(27.96 miles) of 77.45 miles of this line; remaining 63.9000%(49.49 miles) is owned by other members of the CapX2020 joint venture [Percentages are subject to change until CAPX project is complete]

**Schedule Page: 422 Line No.: 9 Column: a**

NSM (0955) ALEXANDRIA SWITCHING STATION-BISON: Xcel Energy owns 36.1000%(48.84 miles) of 135.3 miles of this line; remaining 63.9000%(86.46 miles) is owned by other members of the CapX2020 joint venture [Percentages are subject to change until CAPX project is complete]

**Schedule Page: 422 Line No.: 11 Column: a**

NSM (0956) LYON COUNTY-CEDAR MOUNTAIN: Xcel Energy owns 67.8174%(33.56 miles) of 49.49 miles of this line; remaining 32.1826%(15.93 miles) is owned by other members of the CapX2020 joint venture [Percentages are subject to change until CAPX project is complete]

**Schedule Page: 422 Line No.: 12 Column: a**

NSM (0957) LYON COUNTY-CEDAR MOUNTAIN: Xcel Energy owns 67.8174%(33.56 miles) of 49.49 miles of this line; remaining 32.1826%(15.93 miles) is owned by other members of the CapX2020 joint venture [Percentages are subject to change until CAPX project is complete]

**Schedule Page: 422 Line No.: 13 Column: a**

NSM (0958) CEDAR MOUNTAIN-HELENA: Xcel Energy owns 67.8174%(49.57 miles) of 73.1 miles of this line; remaining 32.1826%(23.53 miles) is owned by other members of the CapX2020 joint venture [Percentages are subject to change until CAPX project is complete]

**Schedule Page: 422 Line No.: 14 Column: a**

NSM (0959) CEDAR MOUNTAIN-HELENA: Xcel Energy owns 67.8174%(49.55 miles) of 73.06 miles of this line; remaining 32.1826%(23.51 miles) is owned by other members of the CapX2020 joint venture [Percentages are subject to change until CAPX project is complete]

**Schedule Page: 422 Line No.: 15 Column: a**

NSM (0960) HELENA-CHUB LAKE: Xcel Energy owns 67.8174%(14.15 miles) of 20.87 miles of this line; remaining 32.1826%(06.72 miles) is owned by other members of the CapX2020 joint venture [Percentages are subject to change until CAPX project is complete]

**Schedule Page: 422 Line No.: 16 Column: a**

NSM (0961) CHUB LAKE-HAMPTON: Xcel Energy owns 67.8174%(12.27 miles) of 18.1 miles of this line; remaining 32.1826%(05.83 miles) is owned by other members of the CapX2020 joint venture [Percentages are subject to change until CAPX project is complete]

**Schedule Page: 422 Line No.: 17 Column: a**

NSM (0962) LYON COUNTY-HAZEL CREEK (LINE #1): Xcel Energy owns 67.8174%(16.41 miles) of 24.2 miles of this line; remaining 32.1826%(07.79 miles) is owned by other members of the CapX2020 joint venture [Percentages are subject to change until CAPX project is complete]

**Schedule Page: 422 Line No.: 18 Column: a**

NSM (0964) HAMPTON-NORTH ROCHESTER: Xcel Energy owns 64.0000%(24.224 miles) of 37.85 miles of this line; remaining 36.0000%(13.626 miles) is owned by other members of the CapX2020 joint venture [Percentages are subject to change until CAPX project is complete]

**Schedule Page: 422 Line No.: 19 Column: a**

NSM (0965) NORTH ROCHESTER-MISSISSIPPI RIVER: Xcel Energy owns 64.0000%(27.78 miles) of 43.4 miles of this line; remaining 36.0000%(15.62 miles) is owned by other members of the CapX2020 joint venture [Percentages are subject to change until CAPX project is complete]

**Schedule Page: 422 Line No.: 24 Column: a**

NSM (0972) BROOKINGS COUNTY-LYON COUNTY: Xcel Energy owns 67.8174%(39.88 miles) of 58.8 miles of this line; remaining 32.1826%(18.92 miles) is owned by other members of the CapX2020 joint venture [Percentages are subject to change until CAPX project is complete]

**Schedule Page: 422 Line No.: 25 Column: a**

NSM (0973) MONTICELLO-QUARRY: Xcel Energy owns 36.1000%(10.39 miles) of 28.77 miles of this line; remaining 63.9000%(18.38 miles) is owned by other members of the CapX2020 joint venture [Percentages are subject to change until CAPX project is complete]

**Schedule Page: 422.3 Line No.: 7 Column: a**

NSM (0922) BOSWELL-CASS LAKE: Xcel Energy owns 29.8962%(15.27 miles) of 51.08 miles of this line; remaining 70.1038%(35.81 miles) is owned by other members of the CapX2020 joint venture [Percentages are static; CAPX project is complete]

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

**Schedule Page: 422.3 Line No.: 8 Column: a**

NSM (0923) CASS LAKE-WILTON: Xcel Energy owns 29.8962%(05.78 miles) of 19.32 miles of this line; remaining 70.1038%(13.54 miles) is owned by other members of the CapX2020 joint venture [Percentages are static; CAPX project is complete]

**Schedule Page: 422.3 Line No.: 9 Column: a**

NSM (0963) HAZEL CREEK-MINNESOTA VALLEY (LINE #1): Xcel Energy owns 67.8174%(03.12 miles) of 4.6 miles of this line; remaining 32.1826%(01.48 miles) is owned by other members of the CapX2020 joint venture [Percentages are subject to change until CAPX project is complete]

**Schedule Page: 422.3 Line No.: 18 Column: a**

NSM (5309) CHESTER-NORTH ROCHESTER: Xcel Energy owns 64.0000%(17.7088 miles) of 27.67 miles of this line; remaining 36.0000%(9.9612 miles) is owned by other members of the CapX2020 joint venture [Percentages are subject to change until CAPX project is complete]

**Schedule Page: 422.3 Line No.: 20 Column: a**

NSM (5310) NORTH ROCHESTER-NORTHERN HILLS: Xcel Energy owns 64.0000%(09.93 miles) of 15.51 miles of this line; remaining 36.0000%(05.58 miles) is owned by other members of the CapX2020 joint venture [Percentages are subject to change until CAPX project is complete]

**Schedule Page: 422.3 Line No.: 23 Column: a**

NSM (5558) CEDAR MOUNTAIN-FRANKLIN: Xcel Energy owns 67.8174%(02.92 miles) of 4.3 miles of this line; remaining 32.1826%(01.38 miles) is owned by other members of the CapX2020 joint venture [Percentages are subject to change until CAPX project is complete]

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.  
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of completed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles (c)	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)		Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	(0964)HAMPTON	NORTH ROCHESTER	24.21	SINGLE POLE	6.00	1	1
2			13.64	SINGLE POLE	6.00	2	2
3	(5309)CHESTER	NORTH ROCHESTER	11.41	SINGLE POLE	7.00	1	1
4			16.26	SINGLE POLE	7.00	2	2
5	(5516)WEST GATE	SCOTT CO	5.27	SINGLE POLE	15.00	2	2
6	(5570)BLUFF CREEK	SCOTT CO	4.86	SINGLE POLE	17.00	2	2
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		75.65		58.00	10	10

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			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
6-397.5kcm	TACSR-V	26/7	345	8,295,643	50,777,593	4,061,966		63,135,202	1
6-397.5kcm	TACSR-V	26/7	345						2
6-397.5kcm	TACSR	26/7	161	523,196	7,794,961	4,559,364		12,877,521	3
6-954kcmil	ACSS	26/7	161						4
3-795kcmil	ACSS	26/7	115	1,099,593	5,048,707	3,694,152		9,842,452	5
3-795kcmil	ACSS	26/7	115		142,937	334,549		477,486	6
									7
									8
									9
									10
									11
									12
									13
									14
									15
									16
									17
									18
									19
									20
									21
									22
									23
									24
									25
									26
									27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
				9,918,432	63,764,198	12,650,031		86,332,661	44

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

**Schedule Page: 424 Line No.: 1 Column: a**

NSM (0964) HAMPTON-NORTH ROCHESTER: Xcel Energy owns 64.0000%(24.224 miles) of 37.85 miles of this line; remaining 36.0000%(13.626 miles) is owned by other members of the CapX2020 joint venture [Percentages are subject to change until CAPX project is complete]

**Schedule Page: 424 Line No.: 1 Column: c**

Line construction less than 0.5 miles in length are not reported as they are considered non-significant per FERC instructions; exception: if entire Line is newly constructed in reporting year. It is not necessary to report minor revisions of lines.

**Schedule Page: 424 Line No.: 3 Column: a**

NSM (5309) CHESTER-NORTH ROCHESTER: Xcel Energy owns 64.0000%(17.7088 miles) of 27.67 miles of this line; remaining 36.0000%(9.9612 miles) is owned by other members of the CapX2020 joint venture [Percentages are subject to change until CAPX project is complete]

**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	A.S.KING-TR09	UNATTENDED TRANSM	345.00	115.00	13.80
2	ADAMS-TR09	UNATTENDED TRANSM	345.00	161.00	13.80
3	ADA-TR01	UNATTENDED DISTRIB	69.00	34.50	
4	AFTON-TR01	UNATTENDED DISTRIB	115.00	34.50	
5	AFTON-TR02	UNATTENDED DISTRIB	115.00	34.50	
6	AIR LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
7	AIR LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
8	AIRPORT-TR01	UNATTENDED DISTRIB	115.00	13.80	
9	AIRPORT-TR02	UNATTENDED DISTRIB	115.00	13.80	
10	ALBANY-TR02	UNATTENDED DISTRIB	69.00	12.50	
11	ALBANY-TR03	UNATTENDED DISTRIB	12.50	12.50	
12	ALDRICH-TR02	UNATTENDED DISTRIB	115.00	13.80	
13	ALDRICH-TR03	UNATTENDED DISTRIB	115.00	13.80	
14	ALDRICH-TR04	UNATTENDED DISTRIB	115.00	13.80	
15	ALEXANDRIA-TR01A,TR01B,TR01C	UNATTENDED DISTRIB	34.50	12.50	
16	ALTURA-TR01	UNATTENDED DISTRIB	69.00	13.80	
17	ANNANDALE-TR01	UNATTENDED DISTRIB	69.00	13.80	
18	APACHE-TR01	UNATTENDED DISTRIB	115.00	13.80	
19	APACHE-TR02	UNATTENDED DISTRIB	115.00	13.80	
20	ARDEN HILLS-TR01	UNATTENDED DISTRIB	115.00	69.00	13.80
21	ARDEN HILLS-TR02	UNATTENDED DISTRIB	115.00	69.00	13.80
22	ARLINGTON-TR01	UNATTENDED DISTRIB	69.00	12.50	
23	ATWATER-TR01	UNATTENDED DISTRIB	69.00	13.80	
24	AVERILL-TR01	UNATTENDED DISTRIB	69.00	23.00	
25	AVON-TR01	UNATTENDED DISTRIB	69.00	12.50	
26	BASSETT CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
27	BASSETT CREEK-TR02	UNATTENDED DISTRIB	115.00	13.80	
28	BATTLE CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
29	BATTLE CREEK-TR02	UNATTENDED DISTRIB	115.00	13.80	
30	BAYTOWN-TR01	UNATTENDED DISTRIB	118.00	13.80	
31	BECKER-TR01	UNATTENDED DISTRIB	69.00	13.80	
32	BECKER-TR02	UNATTENDED DISTRIB	69.00	34.50	
33	BELGRADE-TR01	UNATTENDED DISTRIB	69.00	12.50	
34	BELLE PLAINE-TR01	UNATTENDED DISTRIB	69.00	13.80	
35	BIRCH-TR01	UNATTENDED DISTRIB	69.00	34.50	
36	BIRD ISLAND-TR02	UNATTENDED DISTRIB	69.00	12.50	
37	BLUE HERON-TR01	UNATTENDED DISTRIB	69.00	13.80	
38	BLUE LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
39	BLUE LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
40	BLUE LAKE-TR07	UNATTENDED TRANSM	230.00	115.00	13.80

**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-TR09	UNATTENDED TRANSM	345.00	115.00	13.80
2	BLUFF CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
3	BLUFF CREEK-TR05	UNATTENDED TRANSM	115.00	69.00	13.80
4	BROOKINGS COUNTY-TR09	UNATTENDED TRANSM	345.00	115.00	13.80
5	BROOKINGS COUNTY-TR10	UNATTENDED TRANSM	345.00	115.00	13.80
6	BROOKLYN PARK-TR01	UNATTENDED DISTRIB	115.00	13.80	
7	BROOKLYN PARK-TR02	UNATTENDED DISTRIB	115.00	13.80	
8	BROOK-TR01A,TR01B,TR01C	UNATTENDED DISTRIB	34.50	12.50	
9	BROOTEN-TR01	UNATTENDED DISTRIB	69.00	12.50	
10	BROWNTON-TR01	UNATTENDED DISTRIB	69.00	12.50	
11	BUFFALO LAKE-TR01	UNATTENDED DISTRIB	69.00	12.50	
12	BUFFALO RIDGE-TR01	UNATTENDED TRANSM	115.00	34.50	13.80
13	BUFFALO RIDGE-TR02	UNATTENDED TRANSM	115.00	34.50	13.80
14	BURNSIDE-TR01	UNATTENDED DISTRIB	69.00	13.20	
15	BURNSIDE-TR02	UNATTENDED DISTRIB	69.00	13.80	
16	BUTTERFIELD-TR01	UNATTENDED DISTRIB	69.00	12.50	
17	CANISTOTA JUNCTION-TR01	UNATTENDED DISTRIB	69.00	13.80	
18	CANISTOTA-TR01A,TR01B,TR01C	UNATTENDED DISTRIB	69.00	12.50	
19	CANNON FALLS TRANS-TR06	UNATTENDED DISTRIB	115.00	69.00	
20	CANNON FALLS TRANS-TR07	UNATTENDED TRANSM	115.00	69.00	13.80
21	CANNON FALLS-TR01	UNATTENDED DISTRIB	69.00	12.50	
22	CANOVA-TR01A,TR01B,TR01C	UNATTENDED DISTRIB	34.50	12.50	
23	CANTON-TR01	UNATTENDED DISTRIB	69.00	13.80	
24	CANTON-TR02	UNATTENDED DISTRIB	71.00	13.80	
25	CARVER COUNTY-TR01	UNATTENDED TRANSM	115.00	69.00	34.50
26	CARVER COUNTY-TR02	UNATTENDED TRANSM	115.00	69.00	34.50
27	CASS COUNTY-TR01X,TR01Y	UNATTENDED TRANSM	115.00	23.00	2.50
28	CASS COUNTY-TR02	UNATTENDED DISTRIB	115.00	23.00	
29	CASTLE ROCK-TR01	UNATTENDED DISTRIB	69.00	4.00	
30	CEDAR LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
31	CEDAR LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
32	CEDARVALE-TR01	UNATTENDED DISTRIB	115.00	13.80	
33	CEDARVALE-TR02	UNATTENDED DISTRIB	115.00	13.80	
34	CENTERVILLE-TR01	UNATTENDED DISTRIB	69.00	4.00	
35	CHANARAMBIE-TR01	UNATTENDED TRANSM	115.00	34.50	13.80
36	CHANARAMBIE-TR02	UNATTENDED TRANSM	115.00	34.50	13.80
37	CHANARAMBIE-TR04	UNATTENDED TRANSM	115.00	34.50	13.80
38	CHEMOLITE-TR01	UNATTENDED DISTRIB	115.00	12.50	
39	CHEMOLITE-TR02	UNATTENDED DISTRIB	115.00	12.50	
40	CHERRY CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	

**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	CHERRY CREEK-TR03	UNATTENDED DISTRIB	115.00	34.50	
2	CHISAGO COUNTY-TR02	UNATTENDED DISTRIB	115.00	34.50	
3	CHISAGO COUNTY-TR05	UNATTENDED TRANSM	345.00	115.00	34.50
4	CHISAGO COUNTY-TR06	UNATTENDED TRANSM	345.00	161.00	34.50
5	CHISAGO COUNTY-TR09A,TR09B,TR09C	UNATTENDED TRANSM	500.00	345.00	34.50
6	CHISAGO COUNTY-TR10SA,TR10B,TR10C	UNATTENDED TRANSM	500.00	345.00	34.50
7	CLARA CITY-TR01	UNATTENDED DISTRIB	69.00	12.50	
8	CLARA CITY-TR02	UNATTENDED DISTRIB	88.00	23.00	
9	CLARKS GROVE-TR01	UNATTENDED DISTRIB	69.00	12.50	
10	CLIFF AVENUE-TR01	UNATTENDED DISTRIB	69.00	12.50	
11	CLIFF AVENUE-TR02	UNATTENDED DISTRIB	69.00	13.80	
12	COKATO-TR01	UNATTENDED DISTRIB	69.00	13.80	
13	COLVILL-TR04	UNATTENDED TRANSM	115.00	69.00	13.80
14	COLVILL-TR05	UNATTENDED TRANSM	161.00	115.00	13.80
15	COON CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
16	COON CREEK-TR02	UNATTENDED DISTRIB	115.00	13.80	
17	COON CREEK-TR09	UNATTENDED TRANSM	345.00	115.00	34.50
18	COON CREEK-TR10	UNATTENDED TRANSM	345.00	115.00	34.50
19	COTTAGE GROVE-TR01	UNATTENDED DISTRIB	115.00	13.80	
20	COTTAGE GROVE-TR02	UNATTENDED DISTRIB	115.00	13.80	
21	CREDIT RIVER-TR01	UNATTENDED DISTRIB	69.00	12.50	
22	CREDIT RIVER-TR02	UNATTENDED DISTRIB	69.00	12.50	
23	CROOKED LAKE-TR01	UNATTENDED DISTRIB	119.00	13.80	
24	CROOKED LAKE-TR02	UNATTENDED DISTRIB	119.00	13.80	
25	CROOKED LAKE-TR03	UNATTENDED DISTRIB	115.00	12.50	
26	CROOKED LAKE-TR65A,TR65B,TR65C	UNATTENDED DISTRIB	13.80	12.50	
27	CROSSROADS-TR01	UNATTENDED DISTRIB	115.00	13.80	
28	CROSSROADS-TR02	UNATTENDED DISTRIB	115.00	13.80	
29	CROSSROADS-TR03	UNATTENDED DISTRIB	115.00	13.80	
30	CRYSTAL FOODS-TR01	UNATTENDED DISTRIB	69.00	13.80	
31	DAHLGREN-TR01	UNATTENDED DISTRIB	115.00	13.80	
32	DANUBE-TR01	UNATTENDED DISTRIB	69.00	12.50	
33	DASSEL-TR01	UNATTENDED DISTRIB	69.00	13.80	
34	DAYTONS BLUFF-TR01	UNATTENDED DISTRIB	115.00	13.80	
35	DAYTONS BLUFF-TR02	UNATTENDED DISTRIB	115.00	13.80	
36	DAYTONS BLUFF-TR03	UNATTENDED DISTRIB	115.00	13.80	
37	DEEPHAVEN-TR01	UNATTENDED DISTRIB	69.00	13.80	
38	DEEPHAVEN-TR02	UNATTENDED DISTRIB	69.00	13.80	
39	DELANO-TR01X,TR01Y	UNATTENDED DISTRIB	69.00	7.20	
40	DELL RAPIDS-TR02	UNATTENDED DISTRIB	34.50	12.50	

**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	DODGE CENTER-TR01	UNATTENDED DISTRIB	69.00	34.50	
2	DODGE CENTER-TR02	UNATTENDED DISTRIB	69.00	12.50	
3	DODGE CENTER-TR03	UNATTENDED DISTRIB	69.00	13.80	
4	DOVE PIPELINE-TR01	UNATTENDED DISTRIB	115.00	4.16	
5	DOUGLAS COUNTY-TR01	UNATTENDED TRANSM	115.00	69.00	34.50
6	DOUGLAS COUNTY-TR02	UNATTENDED TRANSM	115.00	69.00	34.50
7	DOUGLAS COUNTY-TR03	UNATTENDED DISTRIB	69.00	13.80	
8	DUNDAS-TR01	UNATTENDED DISTRIB	69.00	13.80	
9	DUNDAS-TR02	UNATTENDED DISTRIB	69.00	13.80	
10	EAGLE LAKE-TR01	UNATTENDED DISTRIB	69.00	12.50	
11	EAST BLOOMINGTON-TR01	UNATTENDED DISTRIB	115.00	13.80	
12	EAST BLOOMINGTON-TR02	UNATTENDED DISTRIB	115.00	13.80	
13	EAST BLOOMINGTON-TR03	UNATTENDED DISTRIB	115.00	13.80	
14	EAST WINONA-TR01	UNATTENDED DISTRIB	69.00	12.50	
15	EASTWOOD-TR01	UNATTENDED DISTRIB	69.00	13.80	
16	EASTWOOD-TR02	UNATTENDED DISTRIB	69.00	13.80	
17	EASTWOOD-TR03	UNATTENDED DISTRIB	115.00	13.80	
18	ECHO-TR01	UNATTENDED DISTRIB	23.00	12.50	
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	161.00	13.80
23	EDEN PRAIRIE-TR10	UNATTENDED TRANSM	345.00	161.00	13.80
24	EDGERTON-TR01	UNATTENDED DISTRIB	23.00	12.50	
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	13.80
35	EMERY-TR01A,TR01B,TR01CC	UNATTENDED DISTRIB	34.50	2.40	
36	ESSIG-TR01A,TR01B,TR01C	UNATTENDED DISTRIB	69.00	2.50	
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	

**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	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 TRANSM	115.00	34.50	13.80
7	FENTON-TR02	UNATTENDED TRANSM	115.00	34.50	13.80
8	FENTON-TR05	UNATTENDED TRANSM	115.00	69.00	13.80
9	FIESTA CITY-TR01	UNATTENDED DISTRIB	69.00	12.50	
10	FIFTH STREET-TR01	UNATTENDED DISTRIB	115.00	13.80	
11	FIFTH STREET-TR02	UNATTENDED DISTRIB	115.00	13.80	
12	FIFTH STREET-TR03	UNATTENDED DISTRIB	115.00	13.80	
13	FIFTH STREET-TR04	UNATTENDED DISTRIB	115.00	13.80	
14	FOLEY-TR01	UNATTENDED DISTRIB	34.50	12.50	
15	FORBES-TR09	UNATTENDED TRANSM	500.00	20.00	
16	FORT RIDGLEY-TR05	UNATTENDED TRANSM	115.00	69.00	13.80
17	FRANKLIN-TR04	UNATTENDED DISTRIB	69.00	23.00	
18	FRANKLIN-TR05	UNATTENDED TRANSM	115.00	69.00	13.80
19	FRANKLIN-TR06	UNATTENDED TRANSM	115.00	69.00	13.80
20	FRANKLIN-TR07	UNATTENDED DISTRIB	69.00	23.00	
21	FRONTENAC-TR01	UNATTENDED DISTRIB	69.00	13.80	
22	GATEWAY-TR01	UNATTENDED DISTRIB	69.00	12.50	
23	GATEWAY-TR02	UNATTENDED DISTRIB	69.00	12.50	
24	GAYLORD-TR01	UNATTENDED DISTRIB	69.00	4.00	
25	GIBBON-TR01	UNATTENDED DISTRIB	69.00	12.50	
26	GLEASON LAKE-TR01	UNATTENDED TRANSM	115.00	69.00	13.80
27	GLEASON LAKE-TR03	UNATTENDED DISTRIB	34.50	13.80	
28	GLEASON LAKE-TR04	UNATTENDED DISTRIB	115.00	34.50	
29	GLEASON LAKE-TR07	UNATTENDED DISTRIB	115.00	13.80	
30	GLEASON LAKE-TR08	UNATTENDED DISTRIB	115.00	13.80	
31	GLEN LAKE-TR01	UNATTENDED DISTRIB	69.00	13.80	
32	GLEN LAKE-TR02	UNATTENDED DISTRIB	69.00	13.80	
33	GLENWOOD-TR01	UNATTENDED DISTRIB	69.00	13.80	
34	GLENWOOD-TR02	UNATTENDED DISTRIB	69.00	12.50	
35	GOODVIEW-TR01	UNATTENDED DISTRIB	69.00	12.50	
36	GOODVIEW-TR02	UNATTENDED DISTRIB	69.00	12.50	
37	GOOSE LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
38	GOOSE LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
39	GOPHER-TR01	UNATTENDED DISTRIB	115.00	13.80	
40	GOPHER-TR02	UNATTENDED DISTRIB	115.00	13.80	

**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	GRANITE CITY-TR01	UNATTENDED DISTRIB	115.00	13.80	
2	GRANITE CITY-TR02	UNATTENDED DISTRIB	115.00	13.80	
3	GRANITE CITY-TR03	UNATTENDED DISTRIB	115.00	34.50	
4	GRANT-TR01	UNATTENDED TRANSM	115.00	69.00	2.40
5	GRANT-TR03	UNATTENDED DISTRIB	115.00	34.50	
6	GREEN ISLE-TR01	UNATTENDED DISTRIB	69.00	12.50	
7	GREENFIELD-TR01	UNATTENDED DISTRIB	69.00	12.50	
8	HADLEY-TR01	UNATTENDED DISTRIB	69.00	13.80	
9	HASSAN-TR01	UNATTENDED DISTRIB	115.00	34.50	
10	HASSAN-TR02	UNATTENDED DISTRIB	115.00	34.50	
11	HASTINGS-TR01	UNATTENDED DISTRIB	69.00	13.80	
12	HASTINGS-TR02	UNATTENDED DISTRIB	69.00	13.80	
13	HATFIELD-TR01A, TR01B, TR01C	UNATTENDED DISTRIB	13.80	6.90	
14	HATTON-TR01	UNATTENDED DISTRIB	69.00	12.50	
15	HAZEL CREEK-TR09	UNATTENDED TRANSM	345.00	230.00	13.80
16	HECTOR-TR01	UNATTENDED DISTRIB	69.00	12.50	
17	HENDERSON-TR01	UNATTENDED DISTRIB	69.00	12.50	
18	HIAWATHA WEST-TR01	UNATTENDED DISTRIB	115.00	13.80	
19	HIGH BRIDGE-TR04	UNATTENDED DISTRIB	115.00	13.80	
20	HOLLYDALE-TR01	UNATTENDED DISTRIB	69.00	13.80	
21	HOLLYDALE-TR02	UNATTENDED DISTRIB	34.50	13.80	
22	HOWARD JUNCTION-TR01A, TR01B, TR01C	UNATTENDED DISTRIB	34.50	12.50	
23	HOWARD LAKE-TR01	UNATTENDED DISTRIB	69.00	13.80	
24	HUGO-TR01	UNATTENDED DISTRIB	115.00	34.50	
25	HUGO-TR02	UNATTENDED DISTRIB	115.00	34.50	
26	HYLAND LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
27	HYLAND LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
28	INDIANA-TR01	UNATTENDED DISTRIB	115.00	13.80	
29	INDIANA-TR02	UNATTENDED DISTRIB	115.00	13.80	
30	INDUSTRIAL-TR01	UNATTENDED DISTRIB	34.50	12.50	
31	INDUSTRIAL-TR02	UNATTENDED DISTRIB	34.50	12.50	
32	INVER GROVE-TR01	UNATTENDED TRANSM	115.00	69.00	13.80
33	INVER GROVE-TR02	UNATTENDED TRANSM	115.00	69.00	13.80
34	INVER HILLS-TR09	UNATTENDED TRANSM	345.00	115.00	13.80
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	

**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	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	118.00	13.80	
6	KOCH REFINERY-TR16	UNATTENDED DISTRIB	115.00	13.80	
7	KOHLMAN LAKE-TR01	UNATTENDED DISTRIB	115.00	34.50	
8	KOHLMAN LAKE-TR02	UNATTENDED DISTRIB	115.00	69.00	34.50
9	KOHLMAN LAKE-TR09	UNATTENDED TRANSM	115.00	69.00	13.80
10	KOHLMAN LAKE-TR10	UNATTENDED TRANSM	345.00	115.00	13.80
11	LA CRESENT-TR01	UNATTENDED DISTRIB	69.00	13.80	
12	LAFAYETTE-TR01	UNATTENDED DISTRIB	69.00	12.50	
13	LAKE CITY-TR01	UNATTENDED DISTRIB	68.80	13.80	
14	LAKE CITY-TR02	UNATTENDED DISTRIB	68.80	13.80	
15	LAKE EMILY-TR01	UNATTENDED DISTRIB	69.00	13.80	
16	LAKE LILAN-TR01	UNATTENDED DISTRIB	69.00	12.50	
17	LAKE PULASKI-TR03	UNATTENDED DISTRIB	115.00	34.50	
18	LAKE PULASKI-TR05	UNATTENDED TRANSM	115.00	69.00	34.50
19	LAKE PULASKI-TR06	UNATTENDED TRANSM	115.00	69.00	13.80
20	LAKE YANKTON-TR01	UNATTENDED TRANSM	115.00	69.00	2.50
21	LAKE YANKTON-TR02	UNATTENDED TRANSM	115.00	69.00	13.80
22	LAKE YANKTON-TR03	UNATTENDED DISTRIB	69.00	13.80	
23	LARIMORE-TR01	UNATTENDED DISTRIB	69.00	12.50	
24	LAWRENCE CREEK-TR01	UNATTENDED DISTRIB	115.00	34.50	
25	LAWRENCE CREEK-TR04	UNATTENDED TRANSM	115.00	69.00	13.80
26	LAWRENCE CREEK-TR05	UNATTENDED TRANSM	161.00	115.00	13.80
27	LAWRENCE-TR01	UNATTENDED DISTRIB	115.00	34.50	
28	LAWRENCE-TR07	UNATTENDED TRANSM	115.00	69.00	13.80
29	LAWRENCE-TR08	UNATTENDED TRANSM	118.00	69.00	
30	LENNOX-TR01	UNATTENDED DISTRIB	69.00	13.80	
31	LESTER PRAIRIE-TR01	UNATTENDED DISTRIB	69.00	23.00	
32	LEXINGTON-TR01	UNATTENDED DISTRIB	115.00	13.80	
33	LEXINGTON-TR02	UNATTENDED DISTRIB	115.00	12.50	
34	LEXINGTON-TR03	UNATTENDED DISTRIB	115.00	34.50	
35	LEXINGTON-TR04	UNATTENDED DISTRIB	34.50	13.80	
36	LINCOLN CO-TR01	UNATTENDED TRANSM	115.00	69.00	13.80
37	LINCOLN CO-TR07	UNATTENDED DISTRIB	115.00	13.80	
38	LINCOLN CO-TR08	UNATTENDED DISTRIB	115.00	12.50	
39	LINDE-TR01	UNATTENDED DISTRIB	115.00	13.80	
40	LINDSTROM-TR01	UNATTENDED DISTRIB	69.00	13.80	

**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	LINDSTROM-TR02	UNATTENDED DISTRIB	69.00	12.50	
2	LINN STREET-TR01	UNATTENDED DISTRIB	69.00	12.50	
3	LINN STREET-TR02	UNATTENDED DISTRIB	69.00	12.50	
4	LONE OAK-TR01	UNATTENDED DISTRIB	115.00	13.80	
5	LONE OAK-TR02	UNATTENDED DISTRIB	115.00	13.80	
6	LONG LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
7	LONG LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
8	LOUISE-TR01	UNATTENDED DISTRIB	115.00	13.80	
9	LOWRY-TR01	UNATTENDED DISTRIB	115.00	13.80	
10	LYON COUNTY-TR01	UNATTENDED TRANSM	115.00	69.00	13.80
11	LYON COUNTY-TR09	UNATTENDED TRANSM	345.00	115.00	34.50
12	M E INTERNATIONAL-TR01	UNATTENDED DISTRIB	115.00	13.80	
13	M E INTERNATIONAL-TR02	UNATTENDED DISTRIB	115.00	13.80	
14	MAIN STREET-TR01	UNATTENDED DISTRIB	115.00	13.80	
15	MAIN STREET-TR02	UNATTENDED DISTRIB	115.00	13.80	
16	MAPLE LAKE-TR01	UNATTENDED DISTRIB	69.00	12.50	
17	MAPLE RIVER-TR05	UNATTENDED TRANSM	230.00	161.00	13.80
18	MAPLE RIVER-TR06	UNATTENDED TRANSM	230.00	115.00	13.80
19	MAPLETON-TR01	UNATTENDED DISTRIB	69.00	13.80	
20	MARION-TR01	UNATTENDED DISTRIB	23.00	12.50	
21	MAXWELL-TR01	UNATTENDED DISTRIB	115.00	4.13	
22	MAYHEW LAKE-TR01	UNATTENDED DISTRIB	115.00	34.50	
23	MAYNARD (TRANSMISSION STATION)-TR01	UNATTENDED DISTRIB	115.00	69.00	
24	MAYNARD-TR01	UNATTENDED DISTRIB	69.00	12.50	
25	MAYVILLE-TR01	UNATTENDED DISTRIB	69.00	12.50	
26	MAYVILLE-TR02	UNATTENDED DISTRIB	69.00	12.50	
27	MAZEPPA-TR01	UNATTENDED DISTRIB	69.00	12.50	
28	MEDFORD JCT-TR01	UNATTENDED DISTRIB	69.00	12.50	
29	MEDICINE LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
30	MEDICINE LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
31	MEDICINE LAKE-TR03	UNATTENDED DISTRIB	115.00	13.80	
32	MEIRE GROVE-TR01	UNATTENDED DISTRIB	69.00	12.50	
33	MERIDAN-TR01	UNATTENDED DISTRIB	69.00	12.50	
34	MERRIAM PARK-TR01	UNATTENDED DISTRIB	115.00	13.80	
35	MERRIAM PARK-TR02	UNATTENDED DISTRIB	115.00	13.80	
36	MERRIAM PARK-TR03	UNATTENDED DISTRIB	115.00	13.80	
37	MIDTOWN-TR01	UNATTENDED DISTRIB	115.00	13.80	
38	MINNEHAHA-TR01	UNATTENDED DISTRIB	115.00	13.80	
39	MINNEHAHA-TR02	UNATTENDED DISTRIB	115.00	13.80	
40	MINNESOTA LAKE-TR01	UNATTENDED DISTRIB	69.00	12.50	

**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	MINNESOTA PIPELINE-TR01	UNATTENDED DISTRIB	115.00	4.16	
2	MINNESOTA VALLEY-TR02	UNATTENDED DISTRIB	69.00	34.50	
3	MINNESOTA VALLEY-TR05	UNATTENDED TRANSM	230.00	115.00	13.80
4	MINNESOTA VALLEY-TR06	UNATTENDED TRANSM	230.00	115.00	13.80
5	MINNESOTA VALLEY-TR11	UNATTENDED TRANSM	115.00	69.00	13.80
6	MINNESOTA VALLEY-TR12	UNATTENDED TRANSM	115.00	69.00	13.80
7	MONTEVIDEO-TR01	UNATTENDED DISTRIB	69.00	12.50	
8	MONTEVIDEO-TR02	UNATTENDED DISTRIB	69.00	12.50	
9	MONTICELLO-TR06	UNATTENDED TRANSM	345.00	230.00	13.80
10	MONTICELLO-TR10	UNATTENDED TRANSM	345.00	161.00	13.80
11	MONTROSE-TR01	UNATTENDED DISTRIB	69.00	12.50	
12	MOORE LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
13	MOORE LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
14	MOORE LAKE-TR03	UNATTENDED DISTRIB	115.00	13.80	
15	MORGAN-TR01	UNATTENDED DISTRIB	69.00	34.50	
16	MORRELL-TR01	UNATTENDED DISTRIB	69.00	12.50	
17	MORRISTOWN-TR01	UNATTENDED DISTRIB	69.00	12.50	
18	MOUND-TR01	UNATTENDED DISTRIB	69.00	13.80	
19	MOUND-TR02	UNATTENDED DISTRIB	69.00	13.80	
20	NERSTRAND-TR01X,TR01Y	UNATTENDED DISTRIB	69.00	12.50	
21	NINE MILE CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
22	NINE MILE CREEK-TR02	UNATTENDED DISTRIB	115.00	13.80	
23	NOBLES COUNTY-TR01	UNATTENDED TRANSM	115.00	34.50	13.80
24	NOBLES COUNTY-TR02	UNATTENDED TRANSM	115.00	34.50	13.80
25	NOBLES COUNTY-TR09	UNATTENDED TRANSM	345.00	115.00	34.50
26	NOBLES COUNTY-TR10	UNATTENDED TRANSM	345.00	115.00	34.50
27	NORDIC-TR01	UNATTENDED DISTRIB	115.00	13.80	
28	NORDIC-TR02	UNATTENDED DISTRIB	115.00	13.80	
29	NORTH BROADWAY-TR01	UNATTENDED DISTRIB	23.00	12.50	
30	NORTH BROADWAY-TR02	UNATTENDED DISTRIB	23.00	12.50	
31	NORTH ROCHESTER-TR09	UNATTENDED TRANSM	345.00	161.00	34.50
32	NORTH STAR STEEL-TR01	UNATTENDED DISTRIB	115.00	13.80	
33	NORTH STAR STEEL-TR02	UNATTENDED DISTRIB	115.00	13.80	
34	NORTH STAR STEEL-TR03	UNATTENDED DISTRIB	115.00	13.80	
35	NORTHFIELD-TR01	UNATTENDED DISTRIB	69.00	13.80	
36	NORTHFIELD-TR02	UNATTENDED DISTRIB	69.00	13.80	
37	OAK PARK-TR01	UNATTENDED TRANSM	115.00	23.00	13.80
38	OAK PARK-TR07	UNATTENDED DISTRIB	115.00	13.80	
39	OAK PARK-TR08	UNATTENDED DISTRIB	115.00	13.80	
40	OAKDALE-TR01	UNATTENDED DISTRIB	115.00	13.80	

**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	OAKDALE-TR02	UNATTENDED DISTRIB	115.00	13.80	
2	ORONO-TR01	UNATTENDED DISTRIB	69.00	13.80	
3	OSSEO-TR01	UNATTENDED DISTRIB	115.00	13.80	
4	OSSEO-TR02	UNATTENDED DISTRIB	115.00	13.80	
5	PARKERS LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
6	PARKERS LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
7	PARKERS LAKE-TR03	UNATTENDED DISTRIB	115.00	13.80	
8	PARKERS LAKE-TR09A,TR09B,TR09C	UNATTENDED TRANSM	345.00	115.00	13.80
9	PARKERS LAKE-TR10A,TR10B,TR10C	UNATTENDED TRANSM	345.00	115.00	13.80
10	PAYNESVILLE TRANSM SUB-TR01	UNATTENDED TRANSM	115.00	69.00	13.80
11	PAYNESVILLE TRANSM SUB-TR02	UNATTENDED TRANSM	115.00	69.00	13.80
12	PAYNESVILLE TRANSM SUB-TR04	UNATTENDED DISTRIB	115.00	34.50	
13	PAYNESVILLE TRANSM SUB-TR09	UNATTENDED TRANSM	230.00	115.00	13.80
14	PINE BEND-TR03	UNATTENDED DISTRIB	69.00	13.80	
15	PINE ISLAND-TR01	UNATTENDED DISTRIB	69.00	12.50	
16	PINE ISLAND-TR02	UNATTENDED DISTRIB	69.00	12.50	
17	PIPESTONE-TR01	UNATTENDED DISTRIB	69.00	12.50	
18	PIPESTONE-TR02	UNATTENDED DISTRIB	69.00	12.50	
19	PIPESTONE-TR03	UNATTENDED DISTRIB	69.00	34.50	
20	PIPESTONE-TR05	UNATTENDED TRANSM	115.00	69.00	2.50
21	PIPESTONE-TR06	UNATTENDED TRANSM	115.00	69.00	13.80
22	PLATO-TR01	UNATTENDED DISTRIB	69.00	12.50	
23	PRAIRIE ISLAND-TR10	UNATTENDED TRANSM	345.00	161.00	13.80
24	PRAIRIE-TR01	UNATTENDED TRANSM	115.00	69.00	13.80
25	PRAIRIE-TR03	UNATTENDED TRANSM	115.00	69.00	13.80
26	PRAIRIE-TR05	UNATTENDED TRANSM	230.00	115.00	13.80
27	PRAIRIE-TR07	UNATTENDED TRANSM	230.00	115.00	13.80
28	PRAIRIE-TR08	UNATTENDED TRANSM	230.00	115.00	13.80
29	PRIOR-TR01	UNATTENDED DISTRIB	115.00	13.80	
30	QUARRY-TR09	UNATTENDED TRANSM	345.00	115.00	34.50
31	RAMSEY-TR01	UNATTENDED DISTRIB	115.00	13.80	
32	RAMSEY-TR02	UNATTENDED DISTRIB	115.00	13.80	
33	RAPIDAN-TR01	UNATTENDED DISTRIB	69.00	13.80	
34	RED RIVER-TR01	UNATTENDED TRANSM	115.00	23.00	13.80
35	RED RIVER-TR02	UNATTENDED DISTRIB	115.00	23.00	
36	RED RIVER-TR03	UNATTENDED TRANSM	115.00	23.00	4.80
37	RED ROCK-TR01	UNATTENDED DISTRIB	115.00	13.80	
38	RED ROCK-TR02	UNATTENDED DISTRIB	115.00	13.80	
39	RED ROCK-TR03	UNATTENDED DISTRIB	115.00	13.80	
40	RED ROCK-TR05	UNATTENDED TRANSM	345.00	230.00	13.80

**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	RED ROCK-TR09	UNATTENDED TRANSM	345.00	161.00	13.80
2	RED ROCK-TR10	UNATTENDED TRANSM	345.00	161.00	13.80
3	RED WING-TR01	UNATTENDED DISTRIB	69.00	13.80	
4	RED WING-TR02	UNATTENDED DISTRIB	69.00	13.80	
5	RENVILLE-TR01	UNATTENDED DISTRIB	69.00	12.50	
6	REYNOLDS-TR01	UNATTENDED DISTRIB	69.00	12.50	
7	RICH SPRING-TR01	UNATTENDED DISTRIB	69.00	13.80	
8	RICH VALLEY-TR01	UNATTENDED DISTRIB	115.00	13.80	
9	RICHMOND-TR01	UNATTENDED DISTRIB	69.00	34.50	
10	RIVERSIDE-TR01	UNATTENDED DISTRIB	115.00	13.80	
11	RIVERSIDE-TR02	UNATTENDED DISTRIB	115.00	13.80	
12	RIVERWOOD-TR01	UNATTENDED DISTRIB	115.00	13.80	
13	RIVERWOOD-TR02	UNATTENDED DISTRIB	115.00	13.80	
14	ROCK RIVER-TR01	UNATTENDED DISTRIB	69.00	23.00	
15	ROGERS LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
16	ROGERS LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
17	ROSE PLACE-TR01	UNATTENDED DISTRIB	115.00	13.80	
18	ROSE PLACE-TR02	UNATTENDED DISTRIB	115.00	13.80	
19	ROSEMOUNT-TR01	UNATTENDED DISTRIB	115.00	34.50	
20	SACRED HEART-TR01	UNATTENDED TRANSM	69.00	13.80	4.36
21	SALEM-TR01A, TR01B, TR01C	UNATTENDED DISTRIB	69.00	34.50	
22	SALEM-TR02	UNATTENDED DISTRIB	69.00	12.50	
23	SALIDA CROSSING-TR01	UNATTENDED DISTRIB	115.00	23.00	
24	SARTELL-TR01	UNATTENDED DISTRIB	34.50	12.50	
25	SAUK RIVER-TR01	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	34.50	
29	SCOTT COUNTY-TR01	UNATTENDED TRANSM	115.00	69.00	13.80
30	SCOTT COUNTY-TR02	UNATTENDED TRANSM	115.00	69.00	13.80
31	SEDAN-TR01	UNATTENDED DISTRIB	69.00	12.50	
32	SHEAS LAKE-TR05	UNATTENDED TRANSM	115.00	69.00	13.80
33	SHEAS LAKE-TR09	UNATTENDED TRANSM	345.00	115.00	13.80
34	SHEPARD-TR01	UNATTENDED DISTRIB	115.00	13.80	
35	SHEPARD-TR02	UNATTENDED DISTRIB	115.00	13.80	
36	SHERCO-TR09	UNATTENDED TRANSM	345.00	115.00	13.80
37	SHEYENNE-TR05	UNATTENDED TRANSM	230.00	161.00	13.80
38	SHEYENNE-TR06	UNATTENDED TRANSM	230.00	115.00	13.80
39	SIBLEY PARK-TR01	UNATTENDED DISTRIB	69.00	13.80	
40	SIBLEY PARK-TR02	UNATTENDED DISTRIB	69.00	13.80	

**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	SIOUX FALLS-TR07	UNATTENDED DISTRIB	69.00	13.80	
2	SIOUX FALLS-TR08	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	13.80
8	SOUTH BEND-TR06	UNATTENDED TRANSM	161.00	115.00	13.80
9	SOUTH HAVEN-TR01	UNATTENDED DISTRIB	69.00	34.50	
10	SOUTH RIDGE-TR01	UNATTENDED DISTRIB	69.00	34.50	
11	SOUTH SIOUX FALLS-TR01	UNATTENDED DISTRIB	69.00	12.50	
12	SOUTH SIOUX FALLS-TR02	UNATTENDED DISTRIB	69.00	12.50	
13	SOUTH SIOUX FALLS-TR03	UNATTENDED DISTRIB	69.00	13.80	
14	SOUTH SIOUX FALLS-TR04	UNATTENDED DISTRIB	69.00	13.80	
15	SOUTHTOWN-TR01	UNATTENDED DISTRIB	115.00	13.80	
16	SOUTHTOWN-TR02	UNATTENDED DISTRIB	115.00	13.80	
17	SOUTHTOWN-TR03	UNATTENDED DISTRIB	115.00	13.80	
18	SOUTH-TR01A,TR01B,TR01C	UNATTENDED DISTRIB	69.00	2.40	
19	SPLIT ROCK-TR06	UNATTENDED TRANSM	161.00	115.00	34.50
20	SPLIT ROCK-TR07	UNATTENDED TRANSM	230.00	161.00	13.80
21	SPLIT ROCK-TR10	UNATTENDED TRANSM	345.00	161.00	13.80
22	SPLIT ROCK-TR11	UNATTENDED TRANSM	345.00	161.00	13.80
23	ST JAMES-TR01	UNATTENDED DISTRIB	69.00	12.50	
24	ST JOHNS-TR01	UNATTENDED DISTRIB	69.00	12.50	
25	ST. CLAIRE-TR01	UNATTENDED DISTRIB	13.20	12.50	
26	ST. CLAIRE-TR02	UNATTENDED DISTRIB	13.20	12.50	
27	ST. CLOUD-TR01	UNATTENDED DISTRIB	115.00	34.50	
28	ST. CLOUD-TR02	UNATTENDED DISTRIB	115.00	34.50	
29	ST. JOSEPH-TR01	UNATTENDED DISTRIB	69.00	12.50	
30	ST. LOUIS PARK-TR02	UNATTENDED DISTRIB	115.00	34.50	
31	ST. LOUIS PARK-TR04	UNATTENDED DISTRIB	115.00	13.80	
32	ST. LOUIS PARK-TR05	UNATTENDED DISTRIB	115.00	13.80	
33	ST. LOUIS PARK-TR06	UNATTENDED DISTRIB	115.00	13.80	
34	ST. PAUL WATER DEPT-TR01	UNATTENDED DISTRIB	23.00	12.50	
35	STEWART-TR01	UNATTENDED DISTRIB	69.00	12.50	
36	STOCKYARDS-TR01	UNATTENDED DISTRIB	115.00	13.80	
37	STOCKYARDS-TR02	UNATTENDED DISTRIB	118.00	13.80	
38	SUMMIT AVENUE-TR01	UNATTENDED DISTRIB	115.00	23.00	
39	SUMMIT AVENUE-TR02	UNATTENDED DISTRIB	115.00	13.80	
40	SWAN LAKE-TR01	UNATTENDED DISTRIB	115.00	12.50	

**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	TANNERS LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
2	TANNERS LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
3	TANNERS LAKE-TR23A1,TR23B1,TR23C1	UNATTENDED DISTRIB	13.80	12.50	
4	TANNERS LAKE-TR23A2,TR23B2,TR23C2	UNATTENDED DISTRIB	13.80	12.50	
5	TANNERS LAKE-TR32A1,TR32B1,TR32C1	UNATTENDED DISTRIB	13.80	12.50	
6	TANNERS LAKE-TR32A2,TR32B2,TR32C2	UNATTENDED DISTRIB	13.80	12.50	
7	TANNERS LAKE-TR34A1,TR34B1,TR34C1	UNATTENDED DISTRIB	13.80	12.50	
8	TANNERS LAKE-TR34A2,TR34B2,TR34C2	UNATTENDED DISTRIB	13.80	12.50	
9	TERMINAL-TR01	UNATTENDED DISTRIB	115.00	13.80	
10	TERMINAL-TR02	UNATTENDED DISTRIB	115.00	13.80	
11	TERMINAL-TR03	UNATTENDED DISTRIB	115.00	13.80	
12	TERMINAL-TR09	UNATTENDED TRANSM	345.00	115.00	34.50
13	TERMINAL-TR10	UNATTENDED TRANSM	345.00	115.00	34.50
14	THOMPSON-TR01	UNATTENDED DISTRIB	69.00	12.50	
15	TRACY SW STA-TR01	UNATTENDED DISTRIB	69.00	13.80	
16	TRACY-TR01	UNATTENDED DISTRIB	69.00	12.50	
17	TWIN LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
18	TWIN LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
19	TWIN LAKE-TR03	UNATTENDED DISTRIB	115.00	13.80	
20	UPPER LEVEE-TR01	UNATTENDED DISTRIB	115.00	23.00	
21	UPPER LEVEE-TR02	UNATTENDED DISTRIB	115.00	13.80	
22	UPPER LEVEE-TR03	UNATTENDED DISTRIB	115.00	13.80	
23	VERMILLION RIVER-TR03	UNATTENDED DISTRIB	115.00	13.80	
24	VERMILLION-TR01	UNATTENDED DISTRIB	23.00	12.50	
25	VESELI-TR01	UNATTENDED DISTRIB	69.00	13.80	
26	VILLARD-TR01	UNATTENDED DISTRIB	69.00	12.50	
27	WABASHA-TR01	UNATTENDED DISTRIB	69.00	13.80	
28	WABASHA-TR02	UNATTENDED DISTRIB	69.00	2.40	
29	WACONIA-TR01	UNATTENDED DISTRIB	69.00	13.80	
30	WAKEFIELD-TR02	UNATTENDED DISTRIB	115.00	34.50	2.30
31	WAKEFIELD-TR02A,TR02B,TR02C	UNATTENDED DISTRIB	34.50	13.80	
32	WAKEFIELD-TR06	UNATTENDED TRANSM	115.00	69.00	13.80
33	WASECA-TR03	UNATTENDED DISTRIB	69.00	23.00	
34	WASECA-TR02	UNATTENDED DISTRIB	69.00	23.00	
35	WASECA-TR04	UNATTENDED DISTRIB	69.00	34.50	
36	WATAB RIVER-TR01	UNATTENDED DISTRIB	69.00	12.50	
37	WATERTOWN-TR01	UNATTENDED DISTRIB	69.00	13.80	
38	WATERVILLE-TR01	UNATTENDED DISTRIB	69.00	34.50	
39	WATERVILLE-TR02	UNATTENDED DISTRIB	69.00	12.50	
40	WATERVILLE-TR03	UNATTENDED DISTRIB	69.00	13.20	

**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	WATKINS-TR01	UNATTENDED DISTRIB	69.00	12.50	
2	WAVERLY-TR01	UNATTENDED DISTRIB	69.00	12.50	
3	WELLS CREEK-TR01	UNATTENDED DISTRIB	69.00	12.50	
4	WESCOTT NATURAL GAS-TR01	UNATTENDED DISTRIB	69.00	2.40	
5	WEST BYRON-TR01	UNATTENDED DISTRIB	69.00	12.50	
6	WEST COON RAPIDS-TR01	UNATTENDED DISTRIB	115.00	34.50	
7	WEST COON RAPIDS-TR02	UNATTENDED DISTRIB	115.00	34.50	
8	WEST COON RAPIDS-TR03	UNATTENDED DISTRIB	34.50	23.00	
9	WEST FARIBAULT-TR01	UNATTENDED TRANSM	115.00	69.00	13.80
10	WEST FARIBAULT-TR02	UNATTENDED TRANSM	115.00	69.00	13.80
11	WEST FARIBAULT-TR03	UNATTENDED DISTRIB	69.00	13.80	
12	WEST FARIBAULT-TR07	UNATTENDED DISTRIB	69.00	13.80	
13	WEST HASTINGS-TR01	UNATTENDED DISTRIB	115.00	12.50	
14	WEST HASTINGS-TR05	UNATTENDED TRANSM	115.00	69.00	13.80
15	WEST NEW ULM-TR05	UNATTENDED TRANSM	115.00	69.00	13.80
16	WEST RIVER RD-TR01	UNATTENDED DISTRIB	115.00	13.80	
17	WEST RIVER RD-TR02	UNATTENDED DISTRIB	115.00	13.80	
18	WEST RIVER RD-TR03	UNATTENDED DISTRIB	115.00	13.80	
19	WEST SIOUX FALLS-TR05	UNATTENDED TRANSM	115.00	69.00	13.80
20	WEST SIOUX FALLS-TR07	UNATTENDED DISTRIB	115.00	13.80	
21	WEST SIOUX FALLS-TR08	UNATTENDED DISTRIB	115.00	13.80	
22	WEST WACONIA-TR01	UNATTENDED DISTRIB	115.00	34.50	
23	WEST WACONIA-TR02	UNATTENDED DISTRIB	115.00	13.80	
24	WESTERN-TR01	UNATTENDED DISTRIB	115.00	13.80	
25	WESTERN-TR02	UNATTENDED DISTRIB	115.00	13.80	
26	WESTGATE-TR01	UNATTENDED TRANSM	115.00	69.00	13.80
27	WESTGATE-TR02	UNATTENDED TRANSM	115.00	69.00	13.80
28	WESTGATE-TR03	UNATTENDED DISTRIB	115.00	13.80	
29	WESTGATE-TR04	UNATTENDED DISTRIB	115.00	13.80	
30	WESTGATE-TR05	UNATTENDED DISTRIB	115.00	34.50	
31	WESTGATE-TR06	UNATTENDED DISTRIB	115.00	34.50	
32	WESTPORT-TR01X,TR01Y	UNATTENDED DISTRIB	69.00	7.50	
33	WILLIAMS BROS PIPE-TR01	UNATTENDED DISTRIB	115.00	13.80	
34	WILLIAMS BROS PIPE-TR02	UNATTENDED DISTRIB	23.00	4.00	
35	WILLIAMS BROS PIPE-TR03	UNATTENDED DISTRIB	115.00	23.00	
36	WILLIAMS BROS PIPE-TR01B	UNATTENDED DISTRIB	15.00	13.80	
37	WILMARTH-TR06	UNATTENDED TRANSM	115.00	69.00	13.80
38	WILMARTH-TR07	UNATTENDED TRANSM	115.00	69.00	13.80
39	WILMARTH-TR08	UNATTENDED TRANSM	115.00	69.00	13.80
40	WILMARTH-TR09	UNATTENDED TRANSM	345.00	161.00	13.80

**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	WILMARTH-TR10	UNATTENDED TRANSM	345.00	115.00	13.80
2	WILSON-TR03	UNATTENDED DISTRIB	115.00	13.80	
3	WILSON-TR04	UNATTENDED DISTRIB	115.00	13.80	
4	WILSON-TR05	UNATTENDED DISTRIB	115.00	13.80	
5	WINONA-TR01	UNATTENDED DISTRIB	69.00	13.80	
6	WINONA-TR02	UNATTENDED DISTRIB	69.00	13.80	
7	WINONA-TR03	UNATTENDED DISTRIB	69.00	13.80	
8	WINSTED-TR01	UNATTENDED DISTRIB	69.00	69.00	13.80
9	WINTHROP-TR01	UNATTENDED DISTRIB	69.00	12.50	
10	WOBEGON TRAIL-TR01	UNATTENDED DISTRIB	69.00	12.50	
11	WOODBURY-TR01	UNATTENDED DISTRIB	115.00	34.50	
12	WOODBURY-TR02	UNATTENDED DISTRIB	115.00	34.50	
13	WYOMING-TR01	UNATTENDED DISTRIB	115.00	12.50	
14	WYOMING-TR02	UNATTENDED DISTRIB	115.00	12.50	
15	YANKEE-TR01	UNATTENDED TRANSM	115.00	34.50	13.80
16	YANKEE-TR02	UNATTENDED TRANSM	115.00	34.50	13.80
17	YELLOW MEDICINE-TR01	UNATTENDED DISTRIB	69.00	34.50	
18	YOUNG AMERICA-TR01	UNATTENDED DISTRIB	69.00	13.80	
19	YOUNG AMERICA-TR02	UNATTENDED DISTRIB	69.00	13.80	
20	ZUMBRO FALLS-TR01	UNATTENDED DISTRIB	69.00	12.50	
21	ZUMBROTA-TR01	UNATTENDED DISTRIB	69.00	12.50	
22					
23					
24	Count TTL Transformer Banks	581			
25	Count TTL Transformers In Service	629			
26	TTL MVA In Service	39,794			
27	Count TTL Substations with Transformers	321			
28	Count TTL Substations without Transformer	28			
29	Count TTL Substations	349			
30	Count TTL Spares	35			
31					
32					
33	Spare Transformers				
34	BROOK-TRSPR	N/A	34.50	4.16	
35	CLARKS GROVE-TRSPR	N/A	69.00	2.40	
36	CANISTOTA JUNCTION-TRST04	N/A	13.80	12.50	
37	EDINA-TRS013	N/A	13.80	0.48	
38	EDINA-TRS014	N/A	13.80	0.48	
39	EDINA-TRS015	N/A	13.80	0.48	
40	EDINA-TRS021	N/A	13.80	0.21	

**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	EDINA-TRS022	N/A	13.80	0.21	
2	EDINA-TRS031	N/A	13.80	0.21	
3	EDINA-TRS032	N/A	13.80	0.21	
4	EDINA-TRS041	N/A	13.80	0.48	
5	EDINA-TRS042	N/A	13.80	0.48	
6	EMERY-TRSPR	N/A	34.50	4.36	
7	GLENWOOD-TRSPR1	N/A	34.50	2.45	
8	HUGO-TRG-CTR	N/A	115.00	14.00	
9	LINDE	N/A	115.00	14.00	
10	MAPLE GROVE	N/A	345.00	161.00	14.00
11	MAPLE GROVE	N/A	345.00	115.00	35.00
12	MAPLE GROVE	N/A	161.00	115.00	14.00
13	MAPLE GROVE	N/A	115.00	35.00	
14	MAPLE GROVE	N/A	69.00	14.00	
15	MAPLE GROVE	N/A	69.00	14.00	
16	MAPLE GROVE	N/A	69.00	14.00	
17	MAPLE GROVE	N/A	69.00	13.00	
18	MAPLE GROVE	N/A	69.00	13.00	
19	MAPLE GROVE	N/A	14.00	5.00	
20	MINNESOTA VALLEY-TRSPR	N/A	69.00	13.80	
21	MINNESOTA VALLEY	N/A	230.00	115.00	15.00
22	MINNESOTA VALLEY	N/A	230.00	115.00	15.00
23	MINNESOTA VALLEY	N/A	230.00	115.00	15.00
24	PAYNESVILLE TRANSM SUB-TRSPR	N/A	34.50	12.50	
25	PAYNESVILLE TRANSM SUB	N/A	115.00	69.00	13.00
26	PAYNESVILLE TRANSM SUB	N/A	115.00	69.00	13.00
27	PORTAL PIPELINE (MINOT)	N/A	14.00	5.00	
28	RED RIVER	N/A	115.00	25.00	
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
448	1					1
300	1					2
14	1					3
70	1					4
70	1					5
25	1					6
25	1					7
47	1					8
47	1					9
11	1					10
6	1					11
70	1					12
70	1					13
70	1					14
2	3					15
7	1					16
14	1					17
70	1					18
70	1					19
70	1					20
70	1					21
6	1					22
14	1					23
4	1					24
14	1					25
28	1					26
25	1					27
48	1					28
48	1					29
28	1					30
6	1					31
5	1					32
4	1					33
7	1					34
10	1					35
3	1					36
9	1					37
25	1					38
25	1					39
336	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
336	1					1
47	1					2
	1					3
448	1					4
448	1					5
28	1					6
25	1					7
2	3					8
6	1					9
1	1					10
3	1					11
120	1					12
120	1					13
7	1					14
11	1					15
2	1					16
8	1					17
3	3					18
11	1					19
11	1					20
5	1					21
1	3					22
14	1					23
14	1					24
70	1					25
70	1					26
50	2					27
47	1					28
1	1					29
47	1					30
47	1					31
20	1					32
23	1					33
2	1					34
120	1					35
120	1					36
120	1					37
25	1					38
25	1					39
37	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
70	1					1
47	1					2
1	1					3
448	1					4
1203	3					5
1203	3					6
7	1					7
14	1					8
3	1					9
7	1					10
11	1					11
9	1					12
112	1					13
187	1					14
25	1					15
47	1					16
672	1					17
672	1					18
47	1					19
47	1					20
14	1					21
14	1					22
47	1					23
47	1					24
28	1					25
10	3					26
28	1					27
25	1					28
22	1					29
14	1					30
14	1					31
7	1					32
6	1					33
63	1					34
63	1					35
63	1					36
28	1					37
28	1					38
	2					39
11	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
5	1					1
14	1					2
8	1					3
8	1					4
47	1					5
70	1					6
47	1					7
12	1					8
28	1					9
5	1					10
47	1					11
47	1					12
47	1					13
11	1					14
28	1					15
28	1					16
1	1					17
1	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
47	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
53	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
53	1					1
14	1					2
14	1					3
14	1					4
11	1					5
120	1					6
120	1					7
28	1					8
11	1					9
84	1					10
84	1					11
84	1					12
84	1					13
3	1					14
168	1					15
70	1					16
5	1					17
70	1					18
70	1					19
2	1					20
4	1					21
28	1					22
28	1					23
5	1					24
3	1					25
112	1					26
28	1					27
70	1					28
47	1					29
70	1					30
28	1					31
28	1					32
14	1					33
5	1					34
28	1					35
28	1					36
47	1					37
47	1					38
47	1					39
47	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
47	1					1
47	1					2
70	1					3
12	1					4
47	1					5
2	1					6
5	1					7
4	1					8
70	1					9
70	1					10
28	1					11
28	1					12
	3					13
2	1					14
336	1					15
3	1					16
3	1					17
42	1					18
47	1					19
25	1					20
28	1					21
1	3					22
14	1					23
70	1					24
70	1					25
47	1					26
47	1					27
47	1					28
47	1					29
6	1					30
6	1					31
63	1					32
63	1					33
550	1					34
14	1					35
14	1					36
14	1					37
14	1					38
3	1					39
2	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
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
11	1					11
1	1					12
28	1					13
28	1					14
7	1					15
4	1					16
28	1					17
47	1					18
46	1					19
15	1					20
15	1					21
11	1					22
5	1					23
28	1					24
70	1					25
336	1					26
70	1					27
112	1					28
67	1					29
14	1					30
9	1					31
47	1					32
47	1					33
70	1					34
47	1					35
42	1					36
50	1					37
30	1					38
50	1					39
11	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
8	1					1
11	1					2
11	1					3
47	1					4
47	1					5
12	1					6
28	1					7
28	1					8
4	1					9
70	1					10
270	1					11
13	1					12
47	1					13
70	1					14
70	1					15
7	1					16
187	1					17
187	1					18
6	1					19
4	1					20
28	1					21
70	1					22
47	1					23
3	1					24
6	1					25
5	1					26
5	1					27
4	1					28
70	1					29
70	1					30
70	1					31
2	1					32
3	1					33
63	1					34
63	1					35
63	1					36
70	1					37
	1					38
28	1					39
2	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
8	1					1
14	1					2
100	1					3
167	1					4
47	1					5
47	1					6
6	1					7
5	1					8
336	1					9
300	1					10
5	1					11
70	1					12
70	1					13
47	1					14
14	1					15
9	1					16
5	1					17
28	1					18
28	1					19
3	2					20
47	1					21
47	1					22
120	1					23
120	1					24
672	1					25
672	1					26
47	1					27
47	1					28
5	1					29
5	1					30
672	1					31
25	1					32
28	1					33
50	1					34
28	1					35
17	1					36
28	1					37
47	1					38
47	1					39
47	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
47	1					1
12	1					2
70	1					3
70	1					4
25	1					5
25	1					6
47	1					7
240	3					8
240	3					9
70	1					10
47	1					11
47	1					12
336	1					13
14	1					14
7	1					15
7	1					16
9	1					17
9	1					18
6	1					19
25	1					20
25	1					21
4	1					22
224	1					23
70	1					24
70	1					25
336	1					26
54	1					27
336	1					28
28	1					29
448	1					30
38	1					31
38	1					32
3	1					33
47	1					34
91	1					35
91	1					36
25	1					37
15	1					38
47	1					39
336	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
448	1					1
448	1					2
17	1					3
17	1					4
7	1					5
6	1					6
14	1					7
28	1					8
5	1					9
47	1					10
47	1					11
15	1					12
15	1					13
8	1					14
47	1					15
47	1					16
47	1					17
47	1					18
70	1					19
5	1					20
4	3					21
3	1					22
14	1					23
7	1					24
70	1					25
15	1					26
28	1					27
14	1					28
38	1					29
38	1					30
	1					31
112	1					32
336	1					33
15	1					34
15	1					35
448	1					36
187	1					37
187	1					38
25	1					39
28	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
28	1					1
28	1					2
14	1					3
47	1					4
47	1					5
28	1					6
47	1					7
100	1					8
1	1					9
7	1					10
7	1					11
6	1					12
28	1					13
28	1					14
70	1					15
70	1					16
38	1					17
1	3					18
112	1					19
336	1					20
448	1					21
448	1					22
14	1					23
4	1					24
5	1					25
5	1					26
42	1					27
42	1					28
4	1					29
70	1					30
70	1					31
70	1					32
70	1					33
5	1					34
6	1					35
47	1					36
47	1					37
28	1					38
47	1					39
11	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
70	1					1
70	1					2
10	3					3
10	3					4
10	3					5
10	3					6
10	3					7
10	3					8
47	1					9
47	1					10
47	1					11
672	1					12
672	1					13
4	1					14
5	1					15
5	1					16
70	1					17
70	1					18
70	1					19
70	1					20
70	1					21
70	1					22
28	1					23
	1					24
4	1					25
3	1					26
11	1					27
15	1					28
22	1					29
10	1					30
2	3					31
38	1					32
28	1					33
14	1					34
28	1					35
7	1					36
11	1					37
5	1					38
2	1					39
3	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
2	1					1
4	1					2
5	1					3
6	1					4
11	1					5
70	1					6
70	1					7
28	1					8
70	1					9
67	1					10
22	1					11
7	1					12
28	1					13
112	1					14
112	1					15
70	1					16
70	1					17
70	1					18
38	1					19
70	1					20
70	1					21
	1					22
42	1					23
70	1					24
70	1					25
42	1					26
25	1					27
70	1					28
70	1					29
70	1					30
70	1					31
	2					32
8	1					33
9	1					34
9	1					35
3	1					36
38	1					37
38	1					38
70	1					39
448	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
448	1					1
70	1					2
70	1					3
42	1					4
22	1					5
22	1					6
25	1					7
11	1					8
6	1					9
5	1					10
47	1					11
47	1					12
28	1					13
28	1					14
120	1					15
120	1					16
14	1					17
9	1					18
11	1					19
4	1					20
14	1					21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
1		1				34
2		1				35
5		1				36
2		1				37
2		1				38
2		1				39
1		1				40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
1		1				1
1		1				2
1		1				3
1		1				4
1		1				5
1		1				6
3		1				7
3		1				8
7		1				9
336		1				10
448		1				11
187		1				12
70		1				13
22		1				14
11		1				15
4		1				16
4		1				17
14		1				18
5		1				19
4		1				20
112		1				21
50		1				22
50		1				23
3		1				24
47		1				25
47		1				26
5		1				27
47		1				28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

**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)
<b>1</b>	<b>Non-power Goods or Services Provided by Affiliated</b>			
2	Interchange agreement	NSP Wisconsin	557 and 566	170,483,158
3	Receipts from Utility Money Pool Arrangement	Xcel Energy Services Inc.	145	-747,500,000
4	Services provided by Xcel Energy Services Inc.	Xcel Energy Services Inc.	see note	
5	Contribution of capital	Xcel Energy Inc.	211	-96,672,311
6	Borrowings under Utility Money Pool Arrangement	Xcel Energy Services Inc.	233	-424,000,000
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
<b>20</b>	<b>Non-power Goods or Services Provided for Affiliate</b>			
21	Company labor, benefits, and related payments	NSP Wisconsin	see note	-8,921,816
22	Interchange agreement	NSP Wisconsin	456	-475,534,059
23	Repayments under Utility Money Pool Arrangement	Xcel Energy Services Inc.	145	424,000,000
24	Investments in Utility Money Pool Arrangement	Xcel Energy Services Inc.	233	747,500,000
25	Dividends on common stock	Xcel Energy Inc.	215/216	395,893,400
26	Advances to Affiliates	United Power and Land Co.	123.1	100,000
27	Company labor, benefits, and related payments	SPS	see note	-349,214
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

<b>Schedule Page: 429 Line No.: 4 Column: c</b>		
Service Function Group	FERC Group	Total
Accounting, Financial Reporting & Taxes	107-CWIP	234,998
	182.3-Reg Assets	453,162
	408-409-Taxes	1,057,135
	417-421-Other Income	(24,488)
	426.1-426.5-Other Income Deductions	82,323
	430-431-Interest Charges	96,522
	500-514-Steam Power Generation	256,659
	517-532-Nuclear Power Generation	3,316
	535-545-Hydraulic Power Generation	389
	546-557-Other Power Generation	129,044
	560-573-Transmission Expenses	311,820
	580-598-Distribution Expenses	9,570
	710-759-Manufactured Gas Production	12,766
	807-813-Other Gas Supply Expenses	27,380
	850-870-Transmission Expenses	187
	871-893-Distribution Expenses	27,104
	908-909-Customer Service and Informational Expenses	4,906
920-935-Administrative and General Expense	13,200,286	
Accounting, Financial Reporting & Taxes Total		15,883,079
Aviation Services	408-409-Taxes	28,009
	426.1-426.5-Other Income Deductions	460
	560-573-Transmission Expenses	217
	920-935-Administrative and General Expense	3,595,693
Aviation Services Total		3,624,379
Business Systems	107-CWIP	89,793,499
	108-Accum Dep	4,175

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

	182.3-Reg Assets	42,800
	408-409-Taxes	994,834
	417-421-Other Income	35,921
	426.1-426.5-Other Income Deductions	243,942
	500-514-Steam Power Generation	1,755,007
	517-532-Nuclear Power Generation	6,407,084
	535-545-Hydraulic Power Generation	5,142
	546-557-Other Power Generation	408,005
	560-573-Transmission Expenses	5,306,739
	580-598-Distribution Expenses	2,925,646
	710-759-Manufactured Gas Production	8
	807-813-Other Gas Supply Expenses	3,211
	814-826-Underground Storage Expenses	1,683
	840-843.9-Other Storage Expenses	14,942
	850-870-Transmission Expenses	129,094
	871-893-Distribution Expenses	1,506,064
	901-905-Customer Accounts Expenses	6,520,727
	908-909-Customer Service and Informational Expenses	31,928
	920-935-Administrative and General Expense	105,686,751
Business Systems Total		221,817,202
Claims Services	408-409-Taxes	42,340
	426.1-426.5-Other Income Deductions	135
	920-935-Administrative and General Expense	729,294
Claims Services Total		771,769
Corporate Communications	107-CWIP	435
	182.3-Reg Assets	672,567
	186-Misc Deferred Debits	1,971
	254-Reg Liab	291
	408-409-Taxes	218,495
	426.1-426.5-Other Income Deductions	2,404,568
	517-532-Nuclear Power Generation	(2,089)
	546-557-Other Power Generation	249,501
	560-573-Transmission Expenses	247
	580-598-Distribution Expenses	370,162
	710-759-Manufactured Gas Production	12,546
	850-870-Transmission Expenses	23,840
	871-893-Distribution Expenses	36,844
	901-905-Customer Accounts Expenses	166
	908-909-Customer Service and Informational Expenses	422,939
	920-935-Administrative and General Expense	4,102,049
Corporate Communications Total		8,514,532
Corporate Strategy & Business Development	408-409-Taxes	48,595

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

	426.1-426.5-Other Income Deductions	3,726
	920-935-Administrative and General Expense	1,262,899
<b>Corporate Strategy &amp; Business Development Total</b>		<b>1,315,220</b>
<b>Customer Service</b>	107-CWIP	31,873
	182.3-Reg Assets	1,859,530
	254-Reg Liab	416,677
	408-409-Taxes	1,028,670
	417-421-Other Income	34,690
	426.1-426.5-Other Income Deductions	1,202
	901-905-Customer Accounts Expenses	20,362,687
	908-909-Customer Service and Informational Expenses	327,028
	920-935-Administrative and General Expense	3,964,554
<b>Customer Service Total</b>		<b>28,026,911</b>
<b>Employee Communications</b>	107-CWIP	12,685
	408-409-Taxes	39,531
	426.1-426.5-Other Income Deductions	875
	517-532-Nuclear Power Generation	1,752
	546-557-Other Power Generation	129,474
	901-905-Customer Accounts Expenses	(1,677)
	908-909-Customer Service and Informational Expenses	38
	920-935-Administrative and General Expense	700,762
<b>Employee Communications Total</b>		<b>883,440</b>
<b>Energy Delivery - Engineering/Design</b>	107-CWIP	7,230,005
	108-Accum Dep	143,330
	408-409-Taxes	713,479
	426.1-426.5-Other Income Deductions	7,443
	500-514-Steam Power Generation	40,384
	517-532-Nuclear Power Generation	7,972
	546-557-Other Power Generation	1,057
	560-573-Transmission Expenses	12,784,860
	580-598-Distribution Expenses	699,325
	710-759-Manufactured Gas Production	99,233
	840-843.9-Other Storage Expenses	343
	850-870-Transmission Expenses	1,285,419
	871-893-Distribution Expenses	26,389
	901-905-Customer Accounts Expenses	3,281
	908-909-Customer Service and Informational Expenses	10
	920-935-Administrative and General Expense	2,707,569
<b>Energy Delivery - Engineering/Design Total</b>		<b>25,750,099</b>
<b>Energy Delivery Construction, Operations &amp; Maintenance (COM)</b>	107-CWIP	2,547,571
	108-Accum Dep	66,837
	408-409-Taxes	597,843
	426.1-426.5-Other Income Deductions	(35,250)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			

FOOTNOTE DATA

	500-514-Steam Power Generation	182
	560-573-Transmission Expenses	5,450,893
	580-598-Distribution Expenses	3,194,127
	710-759-Manufactured Gas Production	19,687
	840-843.9-Other Storage Expenses	90,284
	850-870-Transmission Expenses	740,217
	871-893-Distribution Expenses	453,134
	920-935-Administrative and General Expense	3,713,943
Energy Delivery Construction, Operations & Maintenance (COM) Total		16,839,468
Energy Markets - Fuel Procurement	408-409-Taxes	90,603
	426.1-426.5-Other Income Deductions	27
	500-514-Steam Power Generation	784,470
	546-557-Other Power Generation	127,136
	807-813-Other Gas Supply Expenses	372,830
	920-935-Administrative and General Expense	498,089
Energy Markets - Fuel Procurement Total		1,873,155
Energy Markets Regulated Trading & Marketing	107-CWIP	26,624
	408-409-Taxes	316,922
	426.1-426.5-Other Income Deductions	34,879
	500-514-Steam Power Generation	2,652
	535-545-Hydraulic Power Generation	1,432
	546-557-Other Power Generation	4,157,573
	560-573-Transmission Expenses	458,058
	575.1-575.8-Regional Market Expenses	371,526
	901-905-Customer Accounts Expenses	(214)
	908-909-Customer Service and Informational Expenses	459,022
	920-935-Administrative and General Expense	1,273,312
Energy Markets Regulated Trading & Marketing Total		7,101,786
Energy Supply Business Resources	107-CWIP	7,726,437
	108-Accum Dep	159,589
	183-Preliminary Survey and Investigation Charges	2,958
	254-Reg Liab	172,928
	408-409-Taxes	451,469
	426.1-426.5-Other Income Deductions	(1,677)
	500-514-Steam Power Generation	11,845,770
	517-532-Nuclear Power Generation	566,766
	535-545-Hydraulic Power Generation	54,630
	546-557-Other Power Generation	1,279,220
	560-573-Transmission Expenses	2,241
	580-598-Distribution Expenses	6,604
	840-843.9-Other Storage Expenses	8,304
	850-870-Transmission Expenses	160
	871-893-Distribution Expenses	3,616

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

	908-909-Customer Service and Informational Expenses	2,719
	920-935-Administrative and General Expense	3,739,791
Energy Supply Business Resources Total		26,021,525
Energy Supply Engineering & Environmental	107-CWIP	3,565,544
	108-Accum Dep	502,660
	183-Preliminary Survey and Investigation Charges	1,364
	408-409-Taxes	282,787
	426.1-426.5-Other Income Deductions	(1,734)
	500-514-Steam Power Generation	3,968,945
	517-532-Nuclear Power Generation	29,399
	535-545-Hydraulic Power Generation	2,217
	546-557-Other Power Generation	786,940
	560-573-Transmission Expenses	72,827
	580-598-Distribution Expenses	100,601
	710-759-Manufactured Gas Production	41,631
	850-870-Transmission Expenses	5,815
	871-893-Distribution Expenses	77,229
	901-905-Customer Accounts Expenses	1
	920-935-Administrative and General Expense	2,440,933
Energy Supply Engineering & Environmental Total		11,877,159
Executive Management Services	107-CWIP	759,576
	182.3-Reg Assets	365
	408-409-Taxes	144,563
	417-421-Other Income	125
	426.1-426.5-Other Income Deductions	282,913
	500-514-Steam Power Generation	1,102
	535-545-Hydraulic Power Generation	(50)
	546-557-Other Power Generation	(16,591)
	560-573-Transmission Expenses	(40,507)
	580-598-Distribution Expenses	(11,011)
	850-870-Transmission Expenses	178,715
	871-893-Distribution Expenses	2,582
	901-905-Customer Accounts Expenses	4,241
	908-909-Customer Service and Informational Expenses	630
	920-935-Administrative and General Expense	4,873,191
Executive Management Services Total		6,179,844
Facilities & Real Estate	107-CWIP	2,347,100
	108-Accum Dep	15,959
	408-409-Taxes	221,156
	417-421-Other Income	36,548
	426.1-426.5-Other Income Deductions	92,268
	500-514-Steam Power Generation	2,360,747
	517-532-Nuclear Power Generation	6,753,073

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			

FOOTNOTE DATA

	535-545-Hydraulic Power Generation	14,629
	546-557-Other Power Generation	969,768
	560-573-Transmission Expenses	1,501,532
	575.1-575.8-Regional Market Expenses	3,277
	580-598-Distribution Expenses	2,277,057
	710-759-Manufactured Gas Production	24,412
	760-Rents	319
	807-813-Other Gas Supply Expenses	11,365
	814-826-Underground Storage Expenses	1,283
	840-843.9-Other Storage Expenses	21,267
	850-870-Transmission Expenses	117,455
	871-893-Distribution Expenses	932,815
	908-909-Customer Service and Informational Expenses	239
	920-935-Administrative and General Expense	19,768,804
Facilities & Real Estate Total		37,471,073
Finance & Treasury	182.3-Reg Assets	30,969
	408-409-Taxes	244,946
	417-421-Other Income	(193,053)
	426.1-426.5-Other Income Deductions	2,122
	430-431-Interest Charges	514,900
	546-557-Other Power Generation	275,895
	908-909-Customer Service and Informational Expenses	85
	920-935-Administrative and General Expense	15,662,115
Finance & Treasury Total		16,537,979
Fleet	107-CWIP	74,027
	580-598-Distribution Expenses	471
	850-870-Transmission Expenses	5
	901-905-Customer Accounts Expenses	19,027
	920-935-Administrative and General Expense	95,668
Fleet Total		189,198
Government Affairs	408-409-Taxes	29,686
	426.1-426.5-Other Income Deductions	687,395
	920-935-Administrative and General Expense	803,303
Government Affairs Total		1,520,384
Human Resources	107-CWIP	266,145
	108-Accum Dep	1,301
	408-409-Taxes	732,781
	426.1-426.5-Other Income Deductions	58,292
	500-514-Steam Power Generation	111,160
	517-532-Nuclear Power Generation	1,037,926
	546-557-Other Power Generation	5,802
	560-573-Transmission Expenses	277,009
	580-598-Distribution Expenses	755,382
	850-870-Transmission Expenses	569,855

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			

FOOTNOTE DATA

	871-893-Distribution Expenses	12,112
	908-909-Customer Service and Informational Expenses	224,620
	920-935-Administrative and General Expense	24,063,546
Human Resources Total		28,115,931
Internal Audit	408-409-Taxes	53,789
	417-421-Other Income	1,173
	426.1-426.5-Other Income Deductions	263
	920-935-Administrative and General Expense	1,500,132
Internal Audit Total		1,555,357
Investor Relations	408-409-Taxes	14,831
	426.1-426.5-Other Income Deductions	1,701
	920-935-Administrative and General Expense	1,072,607
Investor Relations Total		1,089,139
Legal	107-CWIP	81,904
	408-409-Taxes	341,283
	426.1-426.5-Other Income Deductions	19,590
	517-532-Nuclear Power Generation	171,663
	710-759-Manufactured Gas Production	97,883
	920-935-Administrative and General Expense	8,410,571
Legal Total		9,122,894
Marketing & Sales	182.3-Reg Assets	20,936,831
	186-Misc Deferred Debits	13,586
	408-409-Taxes	135,440
	417-421-Other Income	245,584
	426.1-426.5-Other Income Deductions	37,845
	850-870-Transmission Expenses	1,332
	901-905-Customer Accounts Expenses	2,186
	908-909-Customer Service and Informational Expenses	1,737,729
	920-935-Administrative and General Expense	5,191,285
Marketing & Sales Total		28,301,818
Payment & Reporting	920-935-Administrative and General Expense	219,443
Payment & Reporting Total		219,443
Payroll	107-CWIP	8,542
	408-409-Taxes	57,231
	426.1-426.5-Other Income Deductions	3,085
	920-935-Administrative and General Expense	1,013,997
Payroll Total		1,082,855
Rates & Regulation	107-CWIP	27,956
	186-Misc Deferred Debits	2,967
	408-409-Taxes	333,630
	417-421-Other Income	1,189
	426.1-426.5-Other Income Deductions	73,405
	546-557-Other Power Generation	338
	560-573-Transmission Expenses	581,877

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/10/2017	Year/Period of Report 2016/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

	580-598-Distribution Expenses	1,619,766
	850-870-Transmission Expenses	3,953
	871-893-Distribution Expenses	246,884
	920-935-Administrative and General Expense	3,786,469
<b>Rates &amp; Regulation Total</b>		<b>6,678,434</b>
<b>Receipts Processing</b>	408-409-Taxes	37,363
	417-421-Other Income	103
	426.1-426.5-Other Income Deductions	844
	901-905-Customer Accounts Expenses	374,676
	920-935-Administrative and General Expense	346,990
<b>Receipts Processing Total</b>		<b>759,976</b>
<b>Supply Chain</b>	107-CWIP	2,754,656
	108-Accum Dep	21,304
	254-Reg Liab	666
	408-409-Taxes	23,688
	426.1-426.5-Other Income Deductions	3,921
	500-514-Steam Power Generation	108
	517-532-Nuclear Power Generation	10
	560-573-Transmission Expenses	104,879
	575.1-575.8-Regional Market Expenses	1,078
	580-598-Distribution Expenses	49,194
	850-870-Transmission Expenses	6,547
	871-893-Distribution Expenses	1,705
	920-935-Administrative and General Expense	873,388
<b>Supply Chain Total</b>		<b>3,841,144</b>
<b>Grand Total</b>		<b>512,745,750</b>

**Schedule Page: 429 Line No.: 21 Column: c**

Accounts charged:

107	(\$8,355,556)
108	(212,840)
184	(41,695)
408.1	7,372
500	(1,547)
501	(25,444)
502	(4,666)
511	(11,275)
512	(107,991)
513	(3,054)
514	(723)
539	(21,394)
544	(969)
549	(408)
553	(6,432)
563	(5,067)
570	(29,230)
571	(39,242)
572	(498)
583	(651)

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 04/10/2017	2016/Q4
FOOTNOTE DATA			

584	(359)
586	(8,959)
587	(127)
588	71,205
592	(4,141)
593	(51,180)
594	(14,467)
597	(1,600)
843.6	(1,001)
870	57,805
874	(12,981)
875	(1,273)
880	(70,728)
887	(2,598)
893	(32,379)
903	(245)
921	(15,054)
925	396
926	27,180
Total	<u>(\$8,921,816)</u>

**Schedule Page: 429 Line No.: 27 Column: c**

Accounts charged:

107	(\$12,923)
108	(2,893)
511	(310)
512	(893)
513	(3,632)
566	(2,000)
570	(3,195)
583	9
584	(4)
585	(7)
586	(999)
588	(293)
592	(709)
593	(581)
594	(86)
921	(320,698)
925	983
926	(983)
Total	<u>(\$349,214)</u>

INDEX

<u>Schedule</u>	<u>Page No.</u>
Accrued and prepaid taxes .....	262-263
Accumulated Deferred Income Taxes .....	234
	272-277
Accumulated provisions for depreciation of	
common utility plant .....	356
utility plant .....	219
utility plant (summary) .....	200-201
Advances	
from associated companies .....	256-257
Allowances .....	228-229
Amortization	
miscellaneous .....	340
of nuclear fuel .....	202-203
Appropriations of Retained Earnings .....	118-119
Associated Companies	
advances from .....	256-257
corporations controlled by respondent .....	103
control over respondent .....	102
interest on debt to .....	256-257
Attestation .....	i
Balance sheet	
comparative .....	110-113
notes to .....	122-123
Bonds .....	256-257
Capital Stock .....	251
expense .....	254
premiums .....	252
reacquired .....	251
subscribed .....	252
Cash flows, statement of .....	120-121
Changes	
important during year .....	108-109
Construction	
work in progress - common utility plant .....	356
work in progress - electric .....	216
work in progress - other utility departments .....	200-201
Control	
corporations controlled by respondent .....	103
over respondent .....	102
Corporation	
controlled by .....	103
incorporated .....	101
CPA, background information on .....	101
CPA Certification, this report form .....	i-ii

<u>Schedule</u>	<u>Page No.</u>
Deferred	
credits, other .....	269
debits, miscellaneous .....	233
income taxes accumulated - accelerated amortization property .....	272-273
income taxes accumulated - other property .....	274-275
income taxes accumulated - other .....	276-277
income taxes accumulated - pollution control facilities .....	234
Definitions, this report form .....	iii
Depreciation and amortization	
of common utility plant .....	356
of electric plant .....	219
	336-337
Directors .....	105
Discount - premium on long-term debt .....	256-257
Distribution of salaries and wages .....	354-355
Dividend appropriations .....	118-119
Earnings, Retained .....	118-119
Electric energy account .....	401
Expenses	
electric operation and maintenance .....	320-323
electric operation and maintenance, summary .....	323
unamortized debt .....	256
Extraordinary property losses .....	230
Filing requirements, this report form	
General information .....	101
Instructions for filing the FERC Form 1 .....	i-iv
Generating plant statistics	
hydroelectric (large) .....	406-407
pumped storage (large) .....	408-409
small plants .....	410-411
steam-electric (large) .....	402-403
Hydro-electric generating plant statistics .....	406-407
Identification .....	101
Important changes during year .....	108-109
Income	
statement of, by departments .....	114-117
statement of, for the year (see also revenues) .....	114-117
deductions, miscellaneous amortization .....	340
deductions, other income deduction .....	340
deductions, other interest charges .....	340
Incorporation information .....	101

<u>Schedule</u>	<u>Page No.</u>
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

<u>Schedule</u>	<u>Page No.</u>
Plant - electric	
accumulated provision for depreciation .....	219
construction work in progress .....	216
held for future use .....	214
in service .....	204-207
leased to others .....	213
Plant - utility and accumulated provisions for depreciation	
amortization and depletion (summary) .....	201
Pollution control facilities, accumulated deferred	
income taxes .....	234
Power Exchanges .....	326-327
Premium and discount on long-term debt .....	256
Premium on capital stock .....	251
Prepaid taxes .....	262-263
Property - losses, extraordinary .....	230
Pumped storage generating plant statistics .....	408-409
Purchased power (including power exchanges) .....	326-327
Reacquired capital stock .....	250
Reacquired long-term debt .....	256-257
Receivers' certificates .....	256-257
Reconciliation of reported net income with taxable income	
from Federal income taxes .....	261
Regulatory commission expenses deferred .....	233
Regulatory commission expenses for year .....	350-351
Research, development and demonstration activities .....	352-353
Retained Earnings	
amortization reserve Federal .....	119
appropriated .....	118-119
statement of, for the year .....	118-119
unappropriated .....	118-119
Revenues - electric operating .....	300-301
Salaries and wages	
directors fees .....	105
distribution of .....	354-355
officers' .....	104
Sales of electricity by rate schedules .....	304
Sales - for resale .....	310-311
Salvage - nuclear fuel .....	202-203
Schedules, this report form .....	2-4
Securities	
exchange registration .....	250-251
Statement of Cash Flows .....	120-121
Statement of income for the year .....	114-117
Statement of retained earnings for the year .....	118-119
Steam-electric generating plant statistics .....	402-403
Substations .....	426
Supplies - materials and .....	227

<u>Schedule</u>	<u>Page No.</u>
Taxes	
accrued and prepaid .....	262-263
charged during year .....	262-263
on income, deferred and accumulated .....	234
	272-277
reconciliation of net income with taxable income for .....	261
Transformers, line - electric .....	429
Transmission	
lines added during year .....	424-425
lines statistics .....	422-423
of electricity for others .....	328-330
of electricity by others .....	332
Unamortized	
debt discount .....	256-257
debt expense .....	256-257
premium on debt .....	256-257
Unrecovered Plant and Regulatory Study Costs .....	230