

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

3 PU-18-145 Filed 05/07/2018 Pages: 225
2017 FERC FORM No. 1
Otter Tail Power Company
Stuart Tommerdahl

Exact Legal Name of Respondent (Company)

Otter Tail Power Company

Year/Period of Report

End of 2017/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 18th of the following year (18 CFR § 141.1), and
- b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

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

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

GENERAL INSTRUCTIONS

- I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.
- II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.
- III. Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.
- IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.
- V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).
- VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.
- VII. For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.
- VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.
- IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

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

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

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

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

termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

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

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

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

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

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

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

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

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

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be 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 Otter Tail Power Company		02 Year/Period of Report End of <u>2017/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) 215 South Cascade Street, PO Box 496, Fergus Falls, MN 56538-0496			
05 Name of Contact Person Jeff Legge		06 Title of Contact Person Controller, Utility	
07 Address of Contact Person (Street, City, State, Zip Code) PO Box 496, Fergus Falls, MN 56538-0496			
08 Telephone of Contact Person, Including Area Code (218) 739-8291	09 This Report Is (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		10 Date of Report (Mo, Da, Yr) 12/31/2017

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 George Bell	03 Signature George Bell	04 Date Signed (Mo, Da, Yr) 04/10/2018
02 Title Chief Financial Officer		

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

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	Not applicable
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	Not applicable
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	Not applicable
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	Not applicable
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	Not applicable
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	Not applicable
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	Not applicable
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	Not applicable
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	Not applicable
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	Not applicable
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	Not applicable
65	Pumped Storage Generating Plant Statistics	408-409	Not applicable
66	Generating Plant Statistics Pages	410-411	

Name of Respondent Otter Tail Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report End of <u>2017/Q4</u>
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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 Otter Tail Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report End of <u>2017/Q4</u>
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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.

Jeff Legge, Controller-Utility
215 South Cascade Street, PO Box 496
Fergus Falls, MN 56538-0496

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.

Minnesota - July 5, 1907

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.

Minnesota - Electric
North Dakota - Electric
South Dakota - Electric

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 Otter Tail Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report <i>(Mo, Da, Yr)</i> 12/31/2017	Year/Period of Report End of <u>2017/Q4</u>
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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.

Otter Tail Corporation, a registered holding company, owns all of the common stock of the respondent.

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	Not applicable.			
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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	Chief Executive Officer, Utility * **	Charles S. MacFarlane	336,300
2			
3	President, Utility	Timothy J. Rogelstad	359,000
4			
5	Vice President, Customer Service	Mark H. Helland	193,458
6			
7	Vice President, Administration [2]	Thomas R. Brause	113,980
8			
9	Chief Financial Officer	George D. Bell	213,792
10			
11	Vice President, Energy Supply [3]	Jan P. Rudolf	197,055
12			
13	General Counsel & Secretary	Jennifer O. Smestad	191,379
14			
15	Vice President, Asset Management	JoAnn M. Thompson	173,468
16			
17	Vice President, Public Relations	Cris M. Oehler	170,715
18			
19	Vice President, Planning and Strategy [5]	Bradley E. Tollerson	194,686
20			
21	Vice President, Information Technology * **	Don L. Redden	135,252
22			
23	Vice President, Regulatory Affairs [5]	Bruce G. Gerhardson	165,824
24			
25	Treasurer * **	Kevin G. Moug	258,600
26			
27	Assistant Secretary * ** [4]	George A. Koeck	236,400
28			
29	Assistant Treasurer * ** [1]	Todd R. Wahlund	81,294
30			
31	Assistant Treasurer * ** [6]	Brian Carlson	34,087
32			
33			
34	[1] Effective 04/10/2017		
35	[2] Removed effective 04/01/2017		
36	[3] Removed effective 10/06/2017		
37	[4] Removed effective 12/19/2017		
38	[5] Effective 10/06/2017		
39	[6] Removed effective 04/10/2017		
40			
41	* This individual is an employee of		
42	Otter Tail Corporation.		
43			
44	** Portion of salary allocated to the Utility.		

Name of Respondent
Otter Tail Power Company

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

Date of Report
(Mo, Da, Yr)
12/31/2017

Year/Period of Report
End of 2017/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1		
2	George A. Koeck, Director, Assistant Secretary [1]	Fargo, North Dakota
3		
4	Charles S. MacFarlane, Director, and CEO, Utility	Fergus Falls, Minnesota
5		
6	Kevin Moug, Director, Treasurer	Fargo, North Dakota
7		
8	Timothy J. Rogelstad, Director, President, Utility	Fergus Falls, Minnesota
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10	John Abbott, Director	Fargo, North Dakota
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12	Jennifer O. Smestad, Director, Secretary [2]	Fergus Falls, Minnesota
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30	[2] Effective 12/19/2017	
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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
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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	MISO FERC Electric Tariff Original Vol. No. 1	ER98-1438-000
2	MISO FERC Electric Tariff 2nd Revised Vol. No. 1	ER04-895-000
3	MISO FERC Electric Tariff 2nd Revised Vol. No. 1	ER05-122-000
4	MISO FERC Electric Tariff 3rd Revised Vol. No. 1	ER04-458-008
5	MISO FERC Electric Tariff 3rd Revised Vol. No. 1	ER06-18-000
6	MISO FERC Electric Tariff 3rd Revised Vol. No. 1	ER06-159-000
7	MISO FERC Electric Tariff 3rd Revised Vol. No. 1	ER09-91-000
8	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER09-1657-000
9	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER09-1779-000
10	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER10-183
11	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER10-686
12	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER10-1492-000
13	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER10-1791
14	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER10-1997-000;001
15	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER11-28-000;001
16	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER11-3279-000
17	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER11-3704-000
18	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-297-000
19	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-312-000
20	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-334-000
21	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-450-000
22	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-715-000;002
23	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-1667-000
24	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER13-263-001
25	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER13-674-000;002
26	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER13-1169-000
27	MISO FERC Electric Tariff	ER13-1169-001
28	MISO FERC Electric Tariff	ER12-480-006;007
29	MISO FERC Electric Tariff	ER13-2379-000;003;004
30	MISO FERC Electric Tariff	ER14-260-000
31	MISO FERC Electric Tariff	ER14-261-000
32	MISO FERC Electric Tariff	ER14-421-000;001
33	MISO FERC Electric Tariff	ER15-358
34	MISO FERC Electric Tariff	ER15-1490
35	MISO FERC Electric Tariff	ER16-1313
36	MISO FERC Electric Tariff	ER16-1534
37	MISO FERC Electric Tariff	ER16-392
38	MISO FERC Electric Tariff	ER16-197
39	MISO FERC Electric Tariff	ER17-1014
40	MISO FERC Electric Tariff	ER17-1393
41		

Name of Respondent
Otter Tail Power Company

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

Date of Report
(Mo, Da, Yr)
12/31/2017

Year/Period of Report
End of 2017/Q4

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

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?
 Yes
 No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20160315-5126	03/15/2016	ER16-1196	Attachment O Annual Informationa	MISO FERC Electric Tariff
2	20170315-5207	03/15/2017	ER17-1234	Attachment O Annual Informationa	MISO FERC Electric Tariff
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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
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Name of Respondent Otter Tail Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report 12/31/2017	Year/Period of Report End of <u>2017/Q4</u>
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
Otter Tail Power Company			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

1. None.
2. None.
3. In July, the FERC approved 4 transactions in each of EC17-96, EC 17-94, EC17-95 and EC17-93. These transactions are authorized prospectively by the Commission in each of the orders in these dockets.

In EC17-96, the FERC approved the transfer of certain transmission facilities from Otter Tail Power Company to Minnkota Power Cooperative in a transaction that closed in 1987 in the amount of \$197,725.

In EC17-95, the FERC approved Otter Tail Power Company purchasing certain transmission facilities from Northern Municipal Power Agency pursuant to a purchase agreement dated October 30, 1986 in an amount of \$5,071,788.

In EC17-94, the FERC approved Otter Tail Power Company transferring to Minnkota Power Cooperative certain transmission facilities pursuant to a transaction valued at approximately \$128,290.

In EC17-93, the FERC approved the sale of certain transmission facilities to MRES in the amount of \$1,489,318. The assets were sold in 1998.

Final accounting entries were submitted to the FERC on May 8, 2017, as further supplement by a filing dated June 26, 2017, related to an underlying transaction approved by the FERC in 2016 (FERC Docket No. EC16-120, Otter Tail Power Co., 156 FERC ¶ 62,061 (2016) (FERC Order approving transaction dated June 22, 2016)). Those final accounting entries were docketed as FERC Docket No. AC17-143, and were approved by FERC Order on August 23, 2017, in that docket.

Supplemental and revised accounting entries were submitted to the FERC on October 18, 2017, in EC17-93, with such entries docketed at FERC Docket No. AC17-254.

Accounting entries for EC17-94 were approved by FERC Order on October 6, 2017, in FERC Docket No. AC17-253.

Accounting entries for EC17-96 were approved by FERC Order on October 5, 2017, in FERC Docket No. AC17-256.
4. None.
5. None.
6. See Footnote 7 in Notes to Financial Statements.

Minnesota Public Utilities Commission authorization given under Docket No. E-017/S-17-337 dated September 1, 2017.
7. None.
8. The average annual increase for full-time nonunion employees was 2.95% effective April 1, 2017. Local Union 1570 received an average increase of 3.5% effective September 1, 2017. Local Unions 203, 239, 524, and 949 received a 3% increase effective November 1, 2017.
9. See Footnote 6 in Notes to Financial Statements.
10. Otter Tail Power Company is a subsidiary of Otter Tail Corporation.
11. (Reserved.)
12. None.
13. Thomas R. Brause, Vice President, Administration, removed effective April 1, 2017. Jan P. Rudolf, Vice President, Energy Supply, removed effective October 6, 2017. Bradley E. Tollerson, title changed to Vice President, Energy Supply, effective October 6, 2017. George Koeck, Assistant Secretary, removed effective December 19, 2017. Bruce G. Gerhardson appointed Vice President, Regulatory Affairs, effective October 6, 2017. Brian Carlson, Assistant Treasurer, removed effective April 10, 2017. Todd R. Wahlund appointed Assistant Treasurer, effective April 10, 2017.
14. Not applicable.

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200-201	1,981,018,120	1,860,356,979
3	Construction Work in Progress (107)	200-201	132,556,715	149,997,025
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		2,113,574,835	2,010,354,004
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	745,531,210	703,060,660
6	Net Utility Plant (Enter Total of line 4 less 5)		1,368,043,625	1,307,293,344
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		1,368,043,625	1,307,293,344
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		579,911	879,911
19	(Less) Accum. Prov. for Depr. and Amort. (122)		0	0
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	0
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)		68,656	76,551
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		1,369,506	1,095,534
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		2,018,073	2,051,996
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		9,800	9,800
36	Special Deposits (132-134)		6,842,190	3,208,360
37	Working Fund (135)		12,462	12,446
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		18,861,634	20,792,118
41	Other Accounts Receivable (143)		7,125,495	5,541,055
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		859,149	884,718
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		7,374	10,447
45	Fuel Stock (151)	227	8,894,145	9,830,796
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	19,244,188	18,822,509
49	Merchandise (155)	227	0	0
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	15,876	31,385

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)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		1,276,704	916,587
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		22,426,606	21,878,276
62	Miscellaneous Current and Accrued Assets (174)		0	-5,684
63	Derivative Instrument Assets (175)		0	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
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)		83,857,325	80,163,377
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		2,461,734	2,619,437
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	2,827,910	3,507,827
72	Other Regulatory Assets (182.3)	232	148,085,267	146,545,983
73	Prelim. Survey and Investigation Charges (Electric) (183)		0	0
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)		267,828	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	60,876	0
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)		1,214,022	1,539,120
82	Accumulated Deferred Income Taxes (190)	234	103,691,997	127,522,091
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		258,609,634	281,734,458
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		1,712,528,657	1,671,243,175

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Power Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2017	2017/Q4
FOOTNOTE DATA			

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

Per its FERC-approved tariff, the Company uses a 13-month average of allowable prepaid expenses for rate-making purposes, illustrated as follows for the current year.

December 31, 2016	916,587
January 31, 2017	2,289,259
February 28, 2017	2,155,877
March 31, 2017	1,800,434
April 30, 2017	3,186,706
May 31, 2017	2,940,258
June 30, 2017	2,837,204
July 31, 2017	2,517,786
August 31, 2017	2,792,046
September 30, 2017	2,414,120
October 31, 2017	2,028,680
November 30, 2017	1,609,191
December 31, 2017	1,276,704
 13-month average for rate-making	 2,212,681

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	500	500
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)		0	0
7	Other Paid-In Capital (208-211)	253	376,988,966	376,988,966
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	178,800,320	169,810,191
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
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)	-1,961,581	-1,641,899
16	Total Proprietary Capital (lines 2 through 15)		553,828,205	545,157,758
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	412,000,000	445,000,000
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	0	0
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		0	0
24	Total Long-Term Debt (lines 18 through 23)		412,000,000	445,000,000
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)		618,804	603,589
29	Accumulated Provision for Pensions and Benefits (228.3)		155,936,999	141,072,156
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	3,624,425
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		8,719,408	8,341,004
35	Total Other Noncurrent Liabilities (lines 26 through 34)		165,275,211	153,641,174
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		112,370,691	42,883,278
38	Accounts Payable (232)		49,338,850	56,764,068
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		2,066,743	1,571,640
41	Customer Deposits (235)		1,071,755	1,074,025
42	Taxes Accrued (236)	262-263	14,109,924	14,801,360
43	Interest Accrued (237)		6,208,534	6,928,094
44	Dividends Declared (238)		0	0
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)		1,352,088	1,364,872
48	Miscellaneous Current and Accrued Liabilities (242)		4,568,417	4,824,021
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		191,087,002	130,211,358
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	21,378,750	22,849,314
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	9,140,505	7,643,891
60	Other Regulatory Liabilities (254)	278	153,703,088	5,323,068
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	4,887,290	2,645,124
63	Accum. Deferred Income Taxes-Other Property (282)		186,474,995	337,387,379
64	Accum. Deferred Income Taxes-Other (283)		14,753,611	21,384,109
65	Total Deferred Credits (lines 56 through 64)		390,338,239	397,232,885
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		1,712,528,657	1,671,243,175

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	430,559,311	420,778,717		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	246,677,605	241,798,227		
5	Maintenance Expenses (402)	320-323	28,046,187	27,423,931		
6	Depreciation Expense (403)	336-337	49,827,070	50,100,398		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	119,876	121,347		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	1,609,138	1,830,060		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		1,004,202	948,563		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		949,660	682,645		
13	(Less) Regulatory Credits (407.4)		1,625,731	2,430,499		
14	Taxes Other Than Income Taxes (408.1)	262-263	15,045,286	14,258,363		
15	Income Taxes - Federal (409.1)	262-263	-213,688	-173,056		
16	- Other (409.1)	262-263	706,552	584,926		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	18,189,846	3,201,434		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	1,531,485	-12,142,002		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,470,564	-1,656,731		
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)		16	17		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		378,404	360,169		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		357,712,342	349,191,762		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117, line 27		72,846,969	71,586,955		

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)		72,846,969	71,586,955		
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)		667,131	640,333		
34	(Less) Expenses of Nonutility Operations (417.1)		431,062	429,796		
35	Nonoperating Rental Income (418)		56,826	56,167		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		155,423	166,189		
38	Allowance for Other Funds Used During Construction (419.1)		986,150	856,829		
39	Miscellaneous Nonoperating Income (421)		2,952,392	5,315,234		
40	Gain on Disposition of Property (421.1)		30,101			
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		4,416,961	6,604,956		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		454,232	472,464		
46	Life Insurance (426.2)					
47	Penalties (426.3)					
48	Exp. for Certain Civic, Political & Related Activities (426.4)		242,641	225,385		
49	Other Deductions (426.5)		446,449	320,964		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		1,143,322	1,018,813		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	7,848	7,848		
53	Income Taxes-Federal (409.2)	262-263	380,146	116,284		
54	Income Taxes-Other (409.2)	262-263	75,637	19,090		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	1,099,778	2,318,646		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	223,654	186,424		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		1,339,755	2,275,444		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		1,933,884	3,310,699		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		23,222,858	23,931,900		
63	Amort. of Debt Disc. and Expense (428)		379,982	396,195		
64	Amortization of Loss on Reaquired Debt (428.1)		325,098	350,978		
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)					
68	Other Interest Expense (431)		2,147,103	884,688		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		740,730	494,942		
70	Net Interest Charges (Total of lines 62 thru 69)		25,334,311	25,068,819		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		49,446,542	49,828,835		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		49,446,542	49,828,835		

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		169,188,039	157,957,063
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		49,446,542	49,828,835
17	Appropriations of Retained Earnings (Acct. 436)			
18	Excess hydro licensing amortization		-39,457	(44,960)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-39,457	(44,960)
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			-40,456,413	(38,552,899)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-40,456,413	(38,552,899)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		178,138,711	169,188,039
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39	Amortization reserve, federal (Account 215.1)		661,609	622,152
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)		661,609	622,152
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		661,609	622,152
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		178,800,320	169,810,191
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)			

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)	49,446,542	49,828,835
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	49,946,947	50,221,745
5	Amortization	1,989,120	2,226,256
6	Vehicle Depreciation allocated to various operating accounts	1,845,271	1,817,963
7			
8	Deferred Income Taxes (Net)	16,609,634	17,350,056
9	Investment Tax Credit Adjustment (Net)	-1,470,564	-1,656,731
10	Net (Increase) Decrease in Receivables	323,548	2,446,892
11	Net (Increase) Decrease in Inventory	514,972	2,773,929
12	Net (Increase) Decrease in Allowances Inventory	15,509	28,032
13	Net Increase (Decrease) in Payables and Accrued Expenses	-6,471,336	8,739,040
14	Net (Increase) Decrease in Other Regulatory Assets	-859,367	-5,333,409
15	Net Increase (Decrease) in Other Regulatory Liabilities	299,764	1,351,603
16	(Less) Allowance for Other Funds Used During Construction	986,150	856,829
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other: (Increase)Decrease in Noncurrent Assets & Deferred Debits	-269,683	173,422
19	Other: Increase(Decrease) in Noncurrent Liabilities & Deferred Credits	12,810,969	6,041,165
20	Other: (Increase)Decrease in Other Current Assets	-914,131	-5,765,411
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	122,831,045	129,386,558
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-114,151,636	-143,232,219
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	300,000	-215,400
30	(Less) Allowance for Other Funds Used During Construction	-986,150	-856,829
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-112,865,486	-142,590,790
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
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			
49	Net (Increase) Decrease in Receivables		-1,100,105
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses	11,880	-4,482,543
53	Other: (Increase) Decrease in Funds on Deposit with Trustee	-3,633,830	-1,360,953
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-116,487,436	-149,534,391
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		
62	Preferred Stock		
63	Common Stock		
64	Other: Debt Issuance Expense	-222,279	-164,818
65			
66	Net Increase in Short-Term Debt (c)	69,487,413	21,877,438
67	Other: Change in Checks Written in Excess of Cash	-2,152,313	-17,882
68	Other: Proceeds from Capital Infusions		37,000,000
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	67,112,821	58,694,738
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-33,000,000	
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-40,456,413	-38,552,899
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-6,343,592	20,141,839
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	17	-5,994
87			
88	Cash and Cash Equivalents at Beginning of Period	22,246	28,240
89			
90	Cash and Cash Equivalents at End of period	22,263	22,246

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 120 Line No.: 5 Column: a

Amortization of intangible plant, plant acquisition adjustments and deferred costs, and debt discount and expense.

Schedule Page: 120 Line No.: 18 Column: a

Changes in miscellaneous deferred debits

Schedule Page: 120 Line No.: 19 Column: a

Includes changes in: other investments, other special funds, clearing accounts, miscellaneous deferred credits, and unamortized loss

Schedule Page: 120 Line No.: 20 Column: a

Includes changes in: notes receivable, prepayments, interest and dividends receivable, accrued utility revenues, miscellaneous current and accrued assets

Schedule Page: 120 Line No.: 53 Column: a

Change in special funds on deposit with fiscal agent

Schedule Page: 120 Line No.: 64 Column: a

Debt issuance expense

Schedule Page: 120 Line No.: 67 Column: a

Change in checks written in excess of cash

Schedule Page: 120 Line No.: 68 Column: a

Proceeds from capital infusions from parent company

Name of Respondent Otter Tail Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report 12/31/2017	Year/Period of Report End of <u>2017/Q4</u>
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NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 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) 12/31/2017	Year/Period of Report 2017/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Reconciliation of Cash and Cash Equivalents (Lines 88 and 90 on Page 121)
With Balance Sheet Accounts (Page 110):

Account 136 – Temporary Cash Investment (Line 38, Page 110), contains amounts which are considered cash equivalents.

	<u>2017</u>	<u>2016</u>
Cash Equivalents	\$ 0	\$ 0
Reconciliation	<u>2017</u>	<u>2016</u>
Cash – Account 131 (Line 35, Page 110)	\$ 9,800	\$ 9,800
Working Fund – Account 135 (Line 37, Page 110)	12,462	12,446
Cash Equivalent – Account (Above)	<u>0</u>	<u>0</u>
	\$ 22,262	\$ 22,246

Otter Tail Power Company
Notes to Financial Statements
For the years ended December 31, 2017 and 2016

1. Summary of Significant Accounting Policies

Organization and Operations

Otter Tail Power Company (OTP) was incorporated in 1907 under the laws of the State of Minnesota and is a wholly owned subsidiary of Otter Tail Corporation.

On July 1, 2009, Otter Tail Corporation completed a holding company reorganization whereby OTP, which had previously been operated as a division of Otter Tail Corporation, became a wholly owned subsidiary of the new parent holding company named Otter Tail Corporation. The new parent holding company was incorporated in June 2009 under the laws of the State of Minnesota in connection with the holding company reorganization.

OTP includes the production, transmission, distribution and sale of electric energy in Minnesota, North Dakota and South Dakota. In addition, OTP is a participant in the Midcontinent Independent System Operator, Inc. (MISO) markets.

OTP provides electricity to more than 130,000 customers in a service area encompassing 70,000 square miles of western Minnesota, eastern North Dakota and northeastern South Dakota. The territory served by OTP is predominantly agricultural. The aggregate population of OTP's retail electric service area is approximately 230,000. In this service area of 422 communities and adjacent rural areas and farms, approximately 126,000 people live in communities having a population of more than 1,000, according to the 2010 census. The only communities served which have a population in excess of 10,000 are Jamestown, North Dakota (15,427); Bemidji, Minnesota (13,431); and Fergus Falls, Minnesota (13,138). As of December 31, 2017, OTP served 132,146 customers. Although there are relatively few large customers, sales to commercial and industrial customers are significant. One customer accounted for 11.7% of the 2017 revenue from the Electric segment.

Related Party

Included in the amounts presented in the balance sheet and income statement are the following related party balances:

<i>(in thousands)</i>	<u>2017</u>	<u>2016</u>
Accounts Receivable	\$ 7	\$ 10
Accounts Payable	2,067	1,572
Operating Revenues	31	34
Other Operation and Maintenance Expenses	10,725	9,582

The related party transactions predominately relate to the allocation of corporate overhead expenses and corporate aircraft usage to OTP and rent charged to Otter Tail Corporation for its use of office space in Fergus Falls. The corporate overhead expenses include such items as labor, professional services, office rent, subscriptions, information technology and general office expenses incurred by Otter Tail Corporation.

These expenses are allocated to OTP based on the type of expenditure, using an allocation methodology as defined in Otter Tail Corporation's Corporate Cost Allocation Manual.

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) 12/31/2017	Year/Period of Report 2017/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Regulation and Accounting Standards Codification (ASC) Topic 980 (ASC 980)

OTP, a regulated electric utility company, accounts for the financial effects of regulation in accordance with ASC 980. This standard allows for the recording of a regulatory asset or liability for costs and revenues that will be collected or refunded through the ratemaking process in the future. In accordance with regulatory treatment, OTP defers utility debt redemption premiums and amortizes such costs over the original life of the reacquired bonds. See note 3 for further discussion.

OTP is subject to various state and federal agency regulations. The accounting policies followed by this business are subject to the Uniform System of Accounts of the Federal Energy Regulatory Commission (FERC).

Financial Statement Presentation and Basis of Accounting

The financial statements are presented on the basis of the accounting requirements of FERC as set forth in its applicable Uniform System of Accounts and this report differs from GAAP. The significant differences consist of the following:

- Comparative statements of net income per share are not presented.
- The accumulated reserve for estimated removal costs is included in the accumulated provision for depreciation for FERC reporting. For GAAP reporting it is reported as a regulatory liability.
- Current and long-term debt is classified in the balance sheet as all long-term debt in accordance with regulatory treatment, while GAAP presentation reflects current and long-term debt separately.
- Debt is reported without adjustment for related unamortized debt issuance costs.
- Accumulated deferred tax assets and liabilities are classified in the balance sheet as gross deferred debits and credits, respectively, while GAAP presentation reflects either a net deferred asset or liability.
- Regulatory assets and liabilities are classified as current and noncurrent for GAAP, while FERC classifies all regulatory assets and liabilities as noncurrent deferred debits and credits, respectively.
- Various revenues and expenses are presented as other income and income deductions for the FERC presentation and reported as operating income and expenses for the GAAP presentation.

Plant, Retirements and Depreciation

Utility plant is stated at original cost. The cost of additions includes contracted work, direct labor and materials, allocable overheads and allowance for funds used during construction. The amount of interest capitalized on electric utility plant was \$741,000 in 2017 and \$495,000 in 2016. The cost of depreciable units of property retired less salvage is charged to accumulated depreciation. Removal costs, when incurred, are charged against the accumulated reserve for estimated removal expenses. Maintenance, repairs and replacement of minor items of property are charged to operating expenses. The provisions for utility depreciation for financial reporting purposes are made on the straight-line method based on the estimated remaining service lives of the properties (5 to 82 years). Such provisions as a percent of the average balance of depreciable electric utility property were 2.74% in 2017 and 2.88% in 2016. Gains or losses on group asset dispositions are taken to the accumulated provision for depreciation reserve and impact current and future depreciation rates.

Recoverability of Long-Lived Assets

OTP reviews its long-lived assets whenever events or changes in circumstances indicate the carrying amount of the assets May not be recoverable. OTP determines potential impairment by comparing the carrying amount of the assets with net cash flows expected to be provided by operating activities of the business or related assets. If the sum of the expected future net cash flows is less than the carrying amount of the assets, OTP would recognize an impairment loss. Such an impairment loss would be measured as the amount by which the carrying amount exceeds the fair value of the asset, where fair value is based on the discounted cash flows expected to be generated by the asset.

Jointly Owned Facilities

OTP is a joint owner in two coal-fired steam-powered electric generation plants: Big Stone Plant near Big Stone City, South Dakota and Coyote Station near Beulah, North Dakota. OTP is also a joint owner, with other regional utilities, in four major in-service transmission lines and one additional major transmission line under construction. The following table provides ownership percentages and amounts included in the OTP's December 31, 2017 and 2016 balance sheets for its share of jointly owned assets in each of these jointly owned facilities:

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Jointly Owned Facilities (dollars in thousands)	OTP Ownership Percentage	Electric Plant in Service	Construction Work in Progress	Accumulated Depreciation	Net Plant
December 31, 2017					
Big Stone Plant	53.9%	\$ 329,942	\$ 1,074	\$ (74,165)	\$ 256,851
Coyote Station	35.0%	177,721	158	(103,944)	73,935
Fargo–Monticello 345 kV line	14.2%	78,192	--	(4,667)	73,525
Brookings–Southeast Twin Cities 345 kV line ¹	4.8%	26,269	--	(1,293)	24,976
Bemidji–Grand Rapids 230 kV line	14.8%	16,331	--	(1,753)	14,578
Big Stone South–Brookings 345 kV line ¹	50.0%	53,225	--	(434)	52,791
Big Stone South–Ellendale 345 kV line ¹	50.0%	--	89,980	--	89,980
December 31, 2016					
Big Stone Plant	53.9%	\$ 328,809	\$ 23	\$ (65,665)	\$ 263,167
Coyote Station	35.0%	176,315	113	(101,499)	74,929
Fargo–Monticello 345 kV line	14.2%	78,298	--	(3,511)	74,787
Brookings–Southeast Twin Cities 345 kV line ¹	4.8%	26,406	--	(924)	25,482
Bemidji–Grand Rapids 230 kV line	14.8%	16,331	--	(1,573)	14,758
Big Stone South–Brookings 345 kV line ¹	50.0%	--	45,050	--	45,050
Big Stone South–Ellendale 345 kV line ¹	50.0%	--	49,160	--	49,160

¹MISO Multi-Value Project (MVP) designation provides for a return on invested funds while under construction under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff).

OTP's share of direct revenue and expenses of the jointly owned facilities is included in operating revenue and expenses in the statements of income.

Coyote Station Lignite Supply Agreement – Variable Interest Entity—In October 2012 the Coyote Station owners, including OTP, entered into a lignite sales agreement (LSA) with Coyote Creek Mining Company, L.L.C. (CCMC), a subsidiary of The North American Coal Corporation, for the purchase of lignite coal to meet the coal supply requirements of Coyote Station for the period beginning in May 2016 and ending in December 2040. The price per ton paid by the Coyote Station owners under the LSA reflects the cost of production, along with an agreed profit and capital charge. CCMC was formed for the purpose of mining coal to meet the coal fuel supply requirements of Coyote Station from May 2016 through December 2040 and, based on the terms of the LSA, is considered a variable interest entity (VIE) due to the transfer of all operating and economic risk to the Coyote Station owners, as the agreement is structured so that the price of the coal would cover all costs of operations as well as future reclamation costs. The Coyote Station owners are also providing a guarantee of the value of the assets of CCMC as they would be required to buy certain assets at book value should they terminate the contract prior to the end of the contract term and are providing a guarantee of the value of the equity of CCMC in that they are required to buy the entity at the end of the contract term at equity value. Under current accounting standards, the primary beneficiary of a VIE is required to include the assets, liabilities, results of operations and cash flows of the VIE in its consolidated financial statements. No single owner of Coyote Station owns a majority interest in Coyote Station and none, individually, has the power to direct the activities that most significantly impact CCMC. Therefore, none of the owners individually, including OTP, is considered a primary beneficiary of the VIE and OTP is not required to include CCMC in OTP's financial statements.

If the LSA terminates prior to the expiration of its term or the production period terminates prior to December 31, 2040 and the Coyote Station owners purchase all of the outstanding membership interests of CCMC as required by the LSA, the owners will satisfy, or (if permitted by CCMC's applicable lender) assume, all of CCMC's obligations owed to CCMC's lenders under its loans and leases. The Coyote Station owners have limited rights to assign their rights and obligations under the LSA without the consent of CCMC's lenders during any period in which CCMC's obligations to its lenders remain outstanding. In the event the contract is terminated because regulations or legislation render the burning of coal cost prohibitive and the assets worthless, OTP's maximum exposure to loss as a result of its involvement with CCMC as of December 31, 2017 could be as high as \$57.1 million, OTP's 35% share of unrecovered costs.

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Income Taxes

Deferred income taxes arise for all temporary differences between the book and tax basis of assets and liabilities. Deferred taxes are recorded using the tax rates scheduled by tax law to be in effect in the periods when the temporary differences reverse. OTP amortizes investment tax credits over the estimated lives of related property. OTP records income taxes in accordance with ASC Topic 740, Income Taxes, and has recognized in its financial statements the tax effects of all tax positions that are “more-likely-than-not” to be sustained on audit based solely on the technical merits of those positions as of the balance sheet date. The term “more-likely-than-not” means a likelihood of more than 50%. See note 11 regarding the OTP’s accounting for uncertain tax positions.

Otter Tail Corporation and its subsidiaries, including OTP, file a consolidated U.S. federal income tax return and various state income tax returns. In OTP’s financial statements, comprehensive interperiod income tax allocation is used for substantially all book and tax temporary differences. In accordance with ASC 740, OTP records separate company deferred tax attribute balances as if OTP filed separate tax returns. OTP’s deferred taxes included \$2.5 million and \$7.9 million of deferred taxes associated with net operating losses that had been utilized by the consolidated group as of December 31, 2017 and 2016, respectively. This deferred tax asset would be reclassified to an intercompany receivable asset in the event the entity were to leave the consolidated return filing group.

OTP also is required to assess the realizability of its deferred tax assets, taking into consideration its forecast of future taxable income, the reversal of other existing temporary differences, available net operating loss carryforwards and available tax planning strategies that could be implemented to realize the deferred tax assets. Based on this assessment, management must evaluate the need for, and amount of, valuation allowances against the OTP’s deferred tax assets. To the extent facts and circumstances change in the future, adjustments to the valuation allowance may be required.

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (TCJA) was signed into law. The major impacts of the changes included in the TCJA are discussed in note 11 to the financial statements.

Revenue Recognition

Customer electricity use is metered and bills are rendered monthly. Revenue is accrued for electricity consumed but not yet billed. Rate schedules applicable to substantially all customers include a fuel clause adjustment, under which the rates are adjusted to reflect changes in average cost of fuels and purchased power, and a surcharge for recovery of conservation-related expenses. Revenue is recognized for fuel and purchased power costs incurred in excess of amounts recovered in base rates but not yet billed through the fuel clause adjustment, for conservation program incentives and bonuses earned but not yet billed and for renewable resource, transmission-related and environmental incurred costs and investment returns approved for recovery through riders.

Revenues on wholesale electricity sales from company-owned generating units are recognized when energy is delivered. For shared use of transmission facilities with certain regional transmission cooperatives, revenues are estimated. Bills are rendered based on anticipated usage and settlements are made later based on actual usage. Estimated revenues may be adjusted prior to settlement, or at the time of settlement, to reflect actual usage.

Under ASC Topic 815, Derivatives and Hedging, OTP accounts for forward energy contracts as derivatives subject to mark-to-market accounting unless those contracts meet the definition of a capacity contract or are not subject to unplanned netting, then OTP accounts for the contracts under the normal purchases and sales exception to mark-to-market accounting.

Use of Estimates

OTP uses estimates based on the best information available in recording transactions and balances resulting from business operations. As better information becomes available (or actual amounts are known), the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Cash Equivalents

OTP considers all highly liquid debt instruments purchased with maturity of 90 days or less to be cash equivalents.

Investments

The following table provides a breakdown of OTP’s investments at December 31:

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<i>(in thousands)</i>	2017	2016
Cost Method – Economic Development Loan Pools	\$ 45	\$ 54
Equity Method – Partnership	24	23
Total Investments	\$ 69	\$ 77

Agreements Subject to Legally Enforceable Netting Arrangements

OTP has certain derivative contracts that are designated as normal purchases and carried at historical cost in the accompanying balance sheet. Individual counterparty exposures for these contracts can be offset according to legally enforceable netting arrangements. OTP does not offset assets and liabilities under legally enforceable netting arrangements on the face of its balance sheet.

Fair Value Measurements

OTP follows ASC Topic 820, Fair Value Measurements and Disclosures (ASC 820), for recurring fair value measurements. ASC 820 provides a single definition of fair value, requires enhanced disclosures about assets and liabilities measured at fair value and establishes a hierarchal framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value.

Inventories

OTP inventories consisting of fuel, materials and supplies are reported at average cost.

Supplemental Disclosures of Cash Flow Information

<i>(in thousands)</i>	As of December 31,	
	2017	2016
Noncash Investing Activities:		
Transactions Related to Capital Additions not Settled in Cash	\$ 13,433	\$ 13,421
<i>(in thousands)</i>	2017	2016
Cash Paid During the Year for:		
Interest (net of amount capitalized)	\$ 25,366	\$ 24,322
Income Tax Payments	\$ 2,348	\$ --

New Accounting Standards Pending Adoption

ASU 2014-09—In May 2014 the Financial Accounting Standards Board (FASB) issued ASU No. 2014-09, *Revenue from Contracts with Customers (Topic 606)* (ASC 606). ASC 606 is a comprehensive, principles-based accounting standard which amends current revenue recognition guidance with the objective of improving revenue recognition requirements by providing a single comprehensive model to determine the measurement of revenue and the timing of revenue recognition. ASC 606 also requires expanded disclosures to enable users of financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers.

Amendments to the ASC in ASU 2014-09, as amended, are effective for fiscal years beginning after December 15, 2017. Application methods permitted are: (1) full retrospective, (2) retrospective using one or more practical expedients and (3) retrospective with the cumulative effect of initial application recognized at the date of initial application. As of December 31, 2017 OTP had reviewed its revenue streams and contracts. Based on review of OTP's revenue streams, OTP has not identified any contracts where the timing of revenue recognition will change as a result of the adoption of the updates in ASU 2016-09. OTP will adopt the updates in ASU 2014-09 on a modified retrospective basis on January 1, 2018, the date of initial application, but will not be recording a cumulative effect adjustment to retained earnings on application of the updates because the adoption of the updates in ASU 606 have no impact on the timing of revenue recognition for OTP. Adoption of ASU 2014-09 will result in additional disclosures related to the nature, timing and certainty of revenues.

OTP will report adjustments to Alternative Revenue Program (ARP) revenues as a separate line item within revenue on the face of its statement of income. The ARP revenue adjustments are recorded on the basis of recoverable costs incurred and returns earned under rate riders and are not considered revenue from contracts with customers.

ASU 2016-02—In February 2016 the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 is a comprehensive amendment of the ASC, creating Topic 842, which will supersede the current requirements under ASC Topic 840 on

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leases and require the recognition of lease assets and lease liabilities on the balance sheet and the disclosure of key information about leasing arrangements. Topic 842 affects any entity that enters into a lease, with some specified scope exemptions. The main difference between previous Generally Accepted Accounting Principles in the United States (GAAP) and Topic 842 is the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under previous GAAP. Topic 842 retains a distinction between finance leases and operating leases. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the classification criteria for distinguishing between capital leases and operating leases in the previous guidance. Topic 842 also requires qualitative and specific quantitative disclosures by lessees and lessors to meet the objective of enabling users of financial statements to assess the amount, timing, and uncertainty of cash flows arising from leases. The amendments in ASU 2016-02 are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early application of the amendments in ASU 2016-02 is permitted. OTP has developed a list of all current leases outstanding and continues to review ASU 2016-02, identifying key impacts to its businesses to determine areas where the amendments in ASU 2016-02 will be applicable and is evaluating transition options. OTP does not currently plan to apply the amendments in ASU 2016-02 to its financial statements prior to 2019.

ASU 2017-07—In March 2017 the FASB issued ASU No. 2017-07, *Compensation—Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU 2017-07), which is intended to improve the presentation of net periodic pension cost and net periodic postretirement benefit cost. ASC Topic 715, *Compensation—Retirement Benefits* (ASC 715), does not prescribe where the amount of net benefit cost should be presented in an employer’s income statement and does not require entities to disclose by line item the amount of net benefit cost that is included in the income statement or capitalized in assets. The amendments in ASU 2017-07 require that an employer report the service cost component of periodic benefit costs in the same line item or items as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit cost as defined in ASC 715 are required to be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. The amendments in ASU 2017-07 also allow only the service cost component to be eligible for capitalization when applicable (for example, as a cost of internally manufactured inventory or a self-constructed asset). The amendments in ASU 2017-07 are effective for annual periods beginning after December 15, 2017, including interim periods within those annual periods. The amendments will be applied retrospectively for the presentation of the service cost component and the other components of net periodic pension cost and net periodic postretirement benefit cost in the income statement and prospectively, on and after the effective date, for the capitalization of the service cost component of net periodic pension cost and net periodic postretirement benefit cost in assets.

The amendments in ASU 2017-07 deviate significantly from current prescribed ratemaking and regulatory accounting treatment of postretirement benefit costs, which require the capitalization of a portion of all the components of net periodic benefit costs be included in rate base additions and provide for rate recovery of the non-capitalized portion of all of the components of net periodic pension costs as recoverable operating expenses. OTP has assessed the impact adoption of the amendments in ASU 2017-07 will have on its financial statements, financial position and results of operations and OTP has determined the regulatory assets to be established in order to reflect the effect of the required regulatory accounting treatment of the non-service cost components that cannot be capitalized to plant in service under the ASU 2017-07 amendments to GAAP. The non-service cost components of the affected net periodic benefit costs will be reported below the operating income line on OTP’s income statement upon adoption of the amendments in ASU 2017-07.

OTP does not plan to adopt the updates in ASU 2017-07 prior to the first quarter of 2018, the required effective period for application of the updates by OTP. OTP’s non-service cost components of net periodic post-retirement benefit costs that were capitalized to plant in service in 2017 that would have been recorded as regulatory assets if the amendments in ASU 2017-07 were applicable in 2017 were \$0.8 million. OTP’s non-service costs components of net periodic postretirement benefit costs included in operating expense that will be included in other income and deductions on adoption of ASU 2017-07 were \$5.6 million in 2017 and \$5.1 million in 2016.

Subsequent Events – Management has evaluated the impact of events occurring after December 31, 2017 up to March 5, 2018, the date the Company’s U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 10, 2018. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

2. Rate and Regulatory Matters

Below are descriptions of OTP’s major capital expenditure projects that have had, or will have, a significant impact on OTP’s revenue

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requirements, rates and alternative revenue recovery mechanisms, followed by summaries of specific electric rate or rider proceedings with the Minnesota Public Utilities Commission (MPUC), the North Dakota Public Service Commission (NDPSC), the South Dakota Public Utilities Commission (SDPUC) and the FERC, impacting OTP's revenues in 2017 and 2016.

Major Capital Expenditure Projects

Big Stone South–Ellendale Multi-Value Transmission Project (MVP)—This is a 345-kiloVolt (kV) transmission line that will extend 163 miles between a substation near Big Stone City, South Dakota and a substation near Ellendale, North Dakota. OTP jointly developed this project with Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., and the parties will have equal ownership interest in the transmission line portion of the project. MISO approved this project as an MVP under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff) in December 2011. MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple areas within the MISO region. The cost allocation is designed to ensure the costs of transmission projects with regional benefits are properly assigned to those who benefit. Construction began on this line in the second quarter of 2016 and is expected to be completed in 2019. OTP's capitalized costs on this project as of December 31, 2017 were approximately \$90.0 million, which includes assets that are 100% owned by OTP.

Big Stone South–Brookings MVP—This 345-kV transmission line extends approximately 70 miles between a substation near Big Stone City, South Dakota and the Brookings County Substation near Brookings, South Dakota. OTP and Northern States Power–Minnesota, a subsidiary of Xcel Energy Inc., jointly developed this project and the parties have equal ownership interest in the transmission line portion of the project. MISO approved this project as an MVP under the MISO Tariff in December 2011. Construction began on this line in the third quarter of 2015 and the line was energized on September 8, 2017. OTP's capitalized costs on this project as of December 31, 2017 were approximately \$72.7 million, which includes assets that are 100% owned by OTP.

Recovery of OTP's major transmission investments is through the MISO Tariff (several as MVPs) and, currently, Minnesota, North Dakota and South Dakota Transmission Cost Recovery (TCR) Riders.

Reagent Costs

OTP's systemwide costs for reagents are expected to increase to approximately \$2.2 million annually through May 2021 when Hoot Lake Plant is expected to be retired. The Minnesota, North Dakota and South Dakota share of costs are approximately 50%, 40% and 10%, respectively. Reagent costs for the Big Stone Plant AQCS and Coyote Station and Hoot Lake Plant Mercury and Air Toxics Standards (MATS) were initially incurred in 2015 when projects went into service.

Minnesota

2016 General Rate Case—The MPUC rendered its final decision in OTP's 2016 general rate case in March 2017 and issued its written order on May 1, 2017. Pursuant to the order, OTP's allowed rate of return on rate base decreased from 8.61% to 7.5056% and its allowed rate of return on equity decreased from 10.74% to 9.41%. On July 6, 2017 the MPUC denied OTP's request for reconsideration of certain of the MPUC's rulings in the rate case and confirmed its May 1, 2017 order.

The MPUC's order also included: (1) the determination that all costs (including FERC allocated costs and revenues) of the Big Stone South–Brookings and Big Stone South–Ellendale MVP projects will be included in the Minnesota TCR rider and jurisdictionally allocated to OTP's Minnesota customers, and (2) approval of OTP's proposal to transition rate base, expenses and revenues from Environmental Cost Recovery (ECR) and TCR riders to base rate recovery, with the transition occurring when final rates are implemented. The rate base balances, expense levels and revenue levels existing in the riders at the time of implementation of final rates will be used to establish the amounts transitioned to base rates. Certain MISO expenses and revenues will remain in the TCR rider to allow for the ongoing refund or recovery of these variable revenues and costs.

Information on interim and final rate increases and interim revenue refunds accrued is detailed in the tables below:

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<i>(\$ in thousands)</i>	Interim Rates	
	Authorized April 14, 2016	Final Rates
Revenue Increase – Annualized based on Test Year Data	\$ 16,816	\$ 10,471
Revenue Percent Increase	9.56%	5.34%
Return on Rate Base	8.07%	7.5056%
Jurisdictional Rate Base based on Test Year Data	\$ 483,000	\$ 471,000
Return on Equity	10.40%	9.41%
Based on Equity to Total Capital of	52.50%	52.50%
Debt to Total Capital	47.50%	47.50%

<i>Interim Revenue (in thousands)</i>	April 16, 2016 through October 31, 2017	
	Billed	\$ 23,289
Accrued Refund	\$ 8,779	
Net Interim Revenue	\$ 14,510	
Interest on Refundable Amount	\$ 265	
Final Refund	\$ 9,044	

In addition to the interim rate refund, OTP is required to refund the difference between (1) amounts collected under its Minnesota ECR and TCR riders based on the return on equity (ROE) approved in its most recent rider update and (2) amounts that would have been collected based on the lower 9.41% ROE approved in its 2016 general rate case going back to April 16, 2016, the date interim rates were implemented. As of October 31, 2017 the revenues collected under the Minnesota ECR and TCR riders subject to refund due to the lower ROE rate and other adjustments were \$0.9 million and \$1.4 million, respectively. These amounts will be refunded to Minnesota customers over a 12-month period through reductions in the Minnesota ECR and TCR rider rates in effect November 1, 2017, as approved by the MPUC. The TCR rate is provisional and subject to revision under a separate docket.

OTP accrued interim and rider rate refunds until final rates became effective, for bills rendered on and after November 1, 2017. The final interim rate refund, including interest, of \$9.0 million was applied as a credit to Minnesota customers' electric bills beginning November 17, 2017.

Minnesota Conservation Improvement Programs (MNCIP)—Under Minnesota law, every regulated public utility that furnishes electric service must make annual investments and expenditures in energy conservation improvements, or make a contribution to the state's energy and conservation account, in an amount equal to at least 1.5% of its gross operating revenues from service provided in Minnesota.

The Minnesota Department of Commerce's (MNDOC) may require a utility to make investments and expenditures in energy conservation improvements whenever it finds that the improvement will result in energy savings at a total cost to the utility less than the cost to the utility to produce or purchase an equivalent amount of a new supply of energy. Such MNDOC orders can be appealed to the MPUC. Investments made pursuant to such orders generally are recoverable costs in rate cases, even though ownership of the improvement may belong to the property owner rather than the utility. OTP recovers conservation related costs not included in base rates under the MNCIP through the use of an annual recovery mechanism approved by the MPUC.

On May 25, 2016 the MPUC adopted the MNDOC's proposed changes to the MNCIP financial incentive. The new model provides utilities an incentive of 13.5% of 2017 net benefits, 12% of 2018 net benefits and 10% of 2019 net benefits, assuming the utility achieves 1.7% savings compared to retail sales. OTP estimates the impact of the new model will reduce the MNCIP financial incentive by approximately 50% compared to the previous incentive mechanism. MNCIP incentives included \$5.0 million approved for 2016.

Based on results from the 2017 MNCIP program year, OTP recognized a financial incentive of \$2.6 million in 2017. The 2017 program resulted in an approximate 10% decrease in energy savings compared to 2016 program results. OTP will request approval for recovery of its 2017 MNCIP program costs not included in base rates, a \$2.6 million financial incentive and an update to the MNCIP

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surcharge from the MPUC by April 1, 2018.

Transmission Cost Recovery Rider—The Minnesota Public Utilities Act (the MPU Act) provides a mechanism for automatic adjustment outside of a general rate proceeding to recover the costs of new transmission facilities that have been previously approved by the MPUC in a Certificate of Need (CON) proceeding, certified by the MPUC as a Minnesota priority transmission project, made to transmit the electricity generated from renewable generation sources ultimately used to provide service to the utility's retail customers, or exempt from the requirement to obtain a Minnesota CON. The MPUC may also authorize cost recovery via such TCR riders for charges incurred by a utility under a federally approved tariff that accrue from other transmission owners' regionally planned transmission projects that have been determined by the MISO to benefit the utility or integrated transmission system. The MPU Act also authorizes TCR riders to recover the costs of new transmission facilities approved by the regulatory commission of the state in which the new transmission facilities are to be constructed, to the extent approval is required by the laws of that state, and determined by the MISO to benefit the utility or integrated transmission system. Finally, under certain circumstances, the MPU Act also authorizes TCR riders to recover the costs associated with distribution planning and investments in distribution facilities to modernize the utility grid. Such TCR riders allow a return on investment at the level approved in a utility's last general rate case. Additionally, following approval of the rate schedule, the MPUC may approve annual rate adjustments filed pursuant to the rate schedule. MISO regional cost allocation allows OTP to recover some of the costs of its transmission investment from other MISO customers.

In OTP's 2016 general rate case order issued on May 1, 2017, the MPUC ordered OTP to include, in the TCR rider retail rate base, Minnesota's jurisdictional share of OTP's investment in the Big Stone South–Brookings and Big Stone South–Ellendale MVP Projects and all revenues received from other utilities under MISO's tariffed rates as a credit in its TCR revenue requirement calculations. In doing so, the MPUC's order diverts interstate wholesale revenues that have been approved by the FERC to offset FERC-approved expenses, effectively reducing OTP's recovery of those FERC-approved expense levels. The MPUC-ordered treatment will result in the projects being treated as retail investments for Minnesota retail ratemaking purposes. Because the FERC's revenue requirements and authorized returns will vary from the MPUC revenue requirements and authorized returns for the project investments over the lives of the projects, the impact of this decision will vary over time and be dependent on the differences between the revenue requirements and returns in the two jurisdictions at any given time. On August 18, 2017 OTP filed an appeal of the MPUC order with the Minnesota Court of Appeals to contest the portion of the order requiring OTP to allocate costs between jurisdictions of the FERC MVP transmission projects in the TCR rider. OTP believes the MPUC-ordered treatment conflicts with federal authority over transmission of electricity in interstate commerce and rates for the transmission of electricity subject to the jurisdiction of the FERC as set forth in the Federal Power Act of 1935, as amended (Federal Power Act). A decision is expected in late 2018.

Environmental Cost Recovery Rider— OTP had an ECR rider for recovery of OTP's Minnesota jurisdictional share of the revenue requirements of its investment in the Big Stone Plant Air Quality Control System (AQCS). The ECR rider provided for a return on the project's construction work in progress (CWIP) balance at the level approved in OTP's 2010 general rate case. In its 2016 general rate case order, the MPUC approved OTP's proposal to transition eligible rate base and expense recovery from the ECR rider to base rate recovery, effective with implementation of final rates in November 2017.

Reagent Costs and Emission Allowances—On July 31, 2014 OTP filed a request with the MPUC to revise its Fuel Clause Adjustment (FCA) rider in Minnesota to include recovery of reagent and emission allowance costs. On March 12, 2015 the MPUC denied OTP's request to revise its FCA rider to include recovery of these costs. These costs were included in OTP's 2016 general rate case in Minnesota and were considered for recovery either through the FCA rider or general rates. In its 2016 general rate case order issued May 1, 2017 the MPUC again denied OTP's request for recovery of test-year reagent costs and emission allowances in base fuel costs or through the FCA rider. Instead, the test-year costs will be recovered in general rates and variability of those costs in excess of amounts included in general rates will only be recovered to the extent actual kilowatt-hour (kwh) sales exceed forecasted kwh sales used to establish general rates.

North Dakota

General Rates—On November 2, 2017 OTP filed a request with the NDPSC for a rate review and an effective increase in annual revenues from non-fuel base rates of \$13.1 million or 8.72%. In the request, OTP proposed an allowed return on rate base of 7.97% and an allowed rate of return on equity of 10.30%. On December 20, 2017 the NDPSC approved OTP's request for interim rates to increase annual revenue collections by \$12.8 million, effective January 1, 2018. OTP used a lower rate of return on equity in the calculation of interim rates based on the rate of return on equity used in its 2018 test-year rate request. In February 2018, in a proceeding before the NDPSC, OTP's interim rate increase was reduced from \$12.8 million to \$8.3 million or from 10.44% to 6.79%.

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effective March 1, 2018. This was in response to a lower revenue requirement related to a reduction in federal corporate income taxes from 35% to 21% in the TCJA.

OTP's most recent general rate increase in North Dakota of \$3.6 million, or approximately 3.0%, was granted by the NDPSC in an order issued on November 25, 2009 and effective December 2009. Pursuant to the order, OTP's allowed rate of return on rate base was set at 8.62%, and its allowed rate of return on equity was set at 10.75%.

Renewable Resource Adjustment—OTP has a North Dakota Renewable Resource Adjustment which enables OTP to recover its North Dakota jurisdictional share of investments in renewable energy facilities. This rider allows OTP to recover costs associated with new renewable energy projects as they are completed, along with a return on investment.

Transmission Cost Recovery Rider—North Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. For qualifying projects, the law authorizes a current return on CWIP and a return on investment at the level approved in the utility's most recent general rate case.

Environmental Cost Recovery Rider—OTP has an ECR rider in North Dakota to recover its North Dakota jurisdictional share of the revenue requirements associated with its investment in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects. The ECR rider provides for a return on investment at the level approved in OTP's most recent general rate case and for recovery of OTP's North Dakota share of reagent and emission allowance costs.

South Dakota

2010 General Rate Case—OTP's most recent general rate increase in South Dakota of approximately \$643,000 or approximately 2.32% was granted by the SDPUC in an order issued on April 21, 2011 and effective with bills rendered on and after June 1, 2011. Pursuant to the order, OTP's allowed rate of return on rate base was set at 8.50%.

Transmission Cost Recovery Rider—South Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities.

Environmental Cost Recovery Rider—OTP has an ECR rider in South Dakota to recover its South Dakota jurisdictional share of revenue requirements associated with its investment in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects.

Reagent Costs and Emission Allowances—On August 1, 2014 OTP filed a request with the SDPUC to revise its FCA rider in South Dakota to include recovery of reagent and emission allowance costs. On September 16, 2014 the SDPUC approved OTP's request to include recovery of these costs in its South Dakota FCA rider.

TCJA

The TCJA reduced the federal corporate income tax rate from 35% to 21%. Currently, all OTP rates have been developed using a 35% tax rate. The MPUC, the NDPSC, the SDPUC and the FERC have all initiated dockets or proceedings to begin working with utilities to assess the impact of the lower income tax rates under the TCJA on electric rates, and develop regulatory strategies to incorporate the tax change into future rates, if warranted. The MPUC required its regulated utilities to make filings by January 30, 2018 and February 15, 2018, but has not made a determination on rate treatment. The SDPUC required initial comments by February 1, 2018 and indicated that revenues collected subsequent to December 31, 2017 would be subject to refund, pending determination of the impacts of the TCJA. OTP is still assessing these impacts and will continue to work with the respective commissions to determine if any rate adjustments are necessary, and if so, to determine the appropriate timing and approach for making those adjustments.

Rate Rider Updates

The following table provides summary information on the status of updates since January 1, 2015 for the rate riders described above:

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) 12/31/2017	Year/Period of Report 2017/Q4
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Rate Rider	R - Request Date A - Approval Date	Effective Date Requested or Approved	Annual Revenue (\$000s)	Rate
Minnesota				
Conservation Improvement Program				
2016 Incentive and Cost Recovery	A – September 15, 2017	October 1, 2017	\$ 9,868	\$0.00536/kwh
2015 Incentive and Cost Recovery	A – July 19, 2016	October 1, 2016	\$ 8,590	\$0.00275/kwh
2014 Incentive and Cost Recovery	A – July 10, 2015	October 1, 2015	\$ 8,689	\$0.00287/kwh
Transmission Cost Recovery				
2017 Rate Reset ¹	A – October 30, 2017	November 1, 2017	\$ (3,311)	Various
2016 Annual Update	A – July 5, 2016	September 1, 2016	\$ 4,736	Various
2015 Annual Update	A – March 9, 2016	April 1, 2016	\$ 7,203	Various
2014 Annual Update	A – February 18, 2015	March 1, 2015	\$ 8,388	Various
Environmental Cost Recovery				
2017 Rate Reset	A – October 30, 2017	November 1, 2017	\$ (1,943)	-0.935% of base
2016 Annual Update	A – July 5, 2016	September 1, 2016	\$11,884	6.927% of base
2015 Annual Update	A – March 9, 2016	October 1, 2015	\$12,104	7.006% of base
North Dakota				
Renewable Resource Adjustment				
2017 Rate Reset	A – December 20, 2017	January 1, 2018	\$ 9,989	7.756% of base
2016 Annual Update	A – March 15, 2017	April 1, 2017	\$ 9,156	7.005% of base
2015 Annual Update	A – June 22, 2016	July 1, 2016	\$ 9,262	7.573% of base
2014 Annual Update	A – March 25, 2015	April 1, 2015	\$ 5,441	4.069% of base
Transmission Cost Recovery				
2017 Annual Update	A – November 29, 2017	January 1, 2018	\$ 7,959	Various
2016 Annual Update	A – December 14, 2016	January 1, 2017	\$ 6,916	Various
2015 Annual Update	A – December 16, 2015	January 1, 2016	\$ 9,985	Various
Environmental Cost Recovery				
2017 Rate Reset	A – December 20, 2017	January 1, 2018	\$ 8,537	6.629% of base
2017 Annual Update	A – July 12, 2017	August 1, 2017	\$ 9,917	7.633% of base
2016 Annual Update	A – June 22, 2016	July 1, 2016	\$10,359	7.904% of base
2015 Annual Update	A – June 17, 2015	July 1, 2015	\$12,249	9.193% of base
South Dakota				
Transmission Cost Recovery				
2017 Annual Update	A – February 28, 2018	March 1, 2018	\$ 1,779	Various
2016 Annual Update	A – February 17, 2017	March 1, 2017	\$ 2,053	Various
2015 Annual Update	A – February 12, 2016	March 1, 2016	\$ 1,895	Various
2014 Annual Update	A – February 13, 2015	March 1, 2015	\$ 1,538	Various
Environmental Cost Recovery				
2017 Annual Update	A – October 13, 2017	November 1, 2017	\$ 2,082	\$0.00483/kwh
2016 Annual Update	A – October 26, 2016	November 1, 2016	\$ 2,238	\$0.00536/kwh
2015 Annual Update	A – October 15, 2015	November 1, 2015	\$ 2,728	\$0.00643/kwh

¹Approved on a provisional basis in the Minnesota general rate case docket and subject to revision in a separate docket.

Revenues Recorded under Rate Riders

The following table presents revenue recorded by OTP under rate riders in place in Minnesota, North Dakota and South Dakota for the years ended December 31:

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) 12/31/2017	Year/Period of Report 2017/Q4
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Rate Rider (in thousands)	2017	2016
Minnesota		
Conservation Improvement Program Costs and Incentives ¹	\$ 9,225	\$12,920
Environmental Cost Recovery	8,148	12,443
Transmission Cost Recovery	2,973	5,795
North Dakota		
Environmental Cost Recovery	9,782	11,089
Transmission Cost Recovery	8,729	7,694
Renewable Resource Adjustment	7,620	7,800
South Dakota		
Environmental Cost Recovery	2,345	2,538
Transmission Cost Recovery	1,843	1,820
Conservation Improvement Program Costs and Incentives	598	468

¹Includes MNCIP costs recovered in base rates.

FERC

Wholesale power sales and transmission rates are subject to the jurisdiction of the FERC under the Federal Power Act. The FERC is an independent agency with jurisdiction over rates for wholesale electricity sales, transmission and sale of electric energy in interstate commerce, interconnection of facilities, and accounting policies and practices. Filed rates are effective after a one-day suspension period, subject to ultimate approval by the FERC.

Multi-Value Transmission Projects—On December 16, 2010 the FERC approved the cost allocation for a new classification of projects in the MISO region called MVPs. MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple transmission zones within the MISO region. The cost allocation is designed to ensure that the costs of transmission projects with regional benefits are properly assigned to those who benefit.

On November 12, 2013 a group of industrial customers and other stakeholders filed a complaint with the FERC seeking to reduce the ROE component of the transmission rates that MISO transmission owners, including OTP, may collect under the MISO Tariff. The complainants sought to reduce the 12.38% ROE used in MISO's transmission rates to a proposed 9.15%. The complaint established a 15-month refund period from November 12, 2013 to February 11, 2015. A non-binding decision by the presiding Administrative Law Judge (ALJ) was issued on December 22, 2015 finding that the MISO transmission owners' ROE should be 10.32%, and the FERC issued an order on September 28, 2016 setting the base ROE at 10.32%. A number of parties requested rehearing of the September 2016 order and the requests are pending FERC action.

On November 6, 2014 a group of MISO transmission owners, including OTP, filed for a FERC incentive of an additional 50-basis points for Regional Transmission Organization participation (RTO Adder). On January 5, 2015 the FERC granted the request, deferring collection of the RTO Adder until the FERC issued its order in the ROE complaint proceeding. Based on the FERC adjustment to the MISO Tariff ROE resulting from the November 12, 2013 complaint and OTP's incentive rate filing, OTP's ROE will be 10.82% (a 10.32% base ROE plus the 0.5% RTO Adder) effective September 28, 2016.

On February 12, 2015 another group of stakeholders filed a complaint with the FERC seeking to reduce the ROE component of the transmission rates that MISO transmission owners, including OTP, may collect under the MISO Tariff from 12.38% to a proposed 8.67%. This second complaint established a second 15-month refund period from February 12, 2015 to May 11, 2016. The FERC issued an order on June 18, 2015 setting the complaint for hearings before an ALJ, which were held the week of February 16, 2016. A non-binding decision by the presiding ALJ was issued on June 30, 2016 finding that the MISO transmission owners' ROE should be 9.7%. OTP is currently waiting for the issuance of a FERC order on the second complaint.

Based on the probable reduction by the FERC in the ROE component of the MISO Tariff, OTP had a \$2.7 million liability on its balance sheet as of December 31, 2016, representing OTP's best estimate of the refund obligations that would arise, net of amounts that would be subject to recovery under state jurisdictional TCR riders, based on a reduced ROE. MISO processed the refund for the FERC-ordered reduction in the MISO Tariff allowed ROE for the first 15-month refund period in its February and June 2017 billings. The refund, in combination with a decision in the 2016 Minnesota general rate case that affected the Minnesota TCR rider, has resulted in a reduction in OTP's accrued MISO Tariff ROE refund liability from \$2.7 million on December 31, 2016 to \$1.6 million as of December 31, 2017.

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In June 2014, the FERC adopted a two-step ROE methodology for electric utilities in an order issued in a complaint proceeding involving New England Transmission Owners (NETOs). The issue of how to apply the FERC ROE methodology has been contested in various complaint proceedings, including the two ROE complaints involving MISO transmission owners discussed above. In April 2017 the Court of Appeals for the District of Columbia (D.C. Circuit) vacated and remanded the FERC's June 2014 ROE order in the NETOs' complaint. The D.C. Circuit found that the FERC had not properly determined that the ROE authorized for NETOs prior to June 2014 was unjust and unreasonable. The D.C. Circuit also found that the FERC failed to justify the new ROE methodology. OTP will await the FERC response to the April 2017 action of the D.C. Circuit before determining if an adjustment to its accrued refund liability is required. On September 29, 2017 the MISO transmission owners filed a motion to dismiss the second complaint based on the D.C. Circuit decision in the NETO complaint. If FERC were to act on a motion to dismiss, it would eliminate the refund obligation from the second complaint and the ROE from the first complaint would remain in effect.

3. Regulatory Assets and Liabilities

As a regulated entity, OTP accounts for the financial effects of regulation in accordance with ASC 980. This accounting standard allows for the recording of a regulatory asset or liability for costs that will be collected or refunded in the future as required under regulation. Additionally, ASC 980-605-25 provides for the recognition of revenues authorized for recovery outside of a general rate case under alternative revenue programs which provide for recovery of costs and incentives or returns on investment in such items as transmission infrastructure, renewable energy resources or conservation initiatives. The following tables indicate the amount of other regulatory assets and liabilities recorded on OTP's balance sheets:

<i>(in thousands)</i>	December 31, 2017	Remaining Recovery/ Refund Period (months)
Other Regulatory Assets:		
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits ¹	\$ 121,577	see below
Conservation Improvement Program Costs and Incentives ²	10,159	21
Accumulated ARO Accretion/Depreciation Adjustment ¹	6,651	asset lives
Deferred Marked-to-Market Losses ¹	6,468	36
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up ²	1,985	24
North Dakota Renewable Resource Rider Accrued Revenues ²	442	15
North Dakota Deferred Rate Case Expenses Subject to Recovery ¹	309	12
Minnesota Deferred Rate Case Expenses Subject to Recovery ¹	267	4
North Dakota Environmental Cost Recovery Rider Accrued Revenues ²	152	12
Minnesota Energy Intensive Trade Exposed Rider Accrued Revenues ²	75	12
Total Other Regulatory Assets	\$ 148,085	
Other Regulatory Liabilities:		
Deferred Income Taxes	\$ 149,052	asset lives
Minnesota Environmental Cost Recovery Rider Accrued Refund	1,667	11
Minnesota Transmission Cost Recovery Rider Accrued Refund	1,411	22
Minnesota Renewable Resource Recovery Rider Accrued Refund	409	12
North Dakota Transmission Cost Recovery Rider Accrued Refund	349	12
Revenue for Rate Case Expenses Subject to Refund – Minnesota	208	4
South Dakota Environmental Cost Recovery Rider Accrued Refund	187	12
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up	180	24
South Dakota Transmission Cost Recovery Rider Accrued Refund	151	12
Other	89	192
Total Other Regulatory Liabilities	\$ 153,703	
Net Other Regulatory Asset/(Liability) Position	\$ (5,618)	

¹Costs subject to recovery without a rate of return.

²Amount eligible for recovery under an alternative revenue program which includes an incentive or rate of return.

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<i>(in thousands)</i>	December 31, 2016	Remaining Recovery/ Refund Period (months)
Other Regulatory Assets:		
Prior Service Costs and Actuarial Losses on Pensions and Other		
Postretirement Benefits ¹	\$114,710	see below
Conservation Improvement Program Costs and Incentives ²	9,994	21
Accumulated ARO Accretion/Depreciation Adjustment ¹	6,153	asset lives
Deferred Marked-to-Market Losses ¹	10,530	48
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up ²	333	12
North Dakota Renewable Resource Rider Accrued Revenues ²	1,801	15
Minnesota Deferred Rate Case Expenses Subject to Recovery ¹	1,082	12
North Dakota Environmental Cost Recovery Rider Accrued Revenues ²	113	12
Deferred Income Taxes ¹	1,014	asset lives
Minnesota Renewable Resource Rider Accrued Revenues ²	34	9
North Dakota Transmission Cost Recovery Rider Accrued Revenues ²	568	24
South Dakota Transmission Cost Recovery Rider Accrued Revenues ²	214	14
Total Other Regulatory Assets	\$146,546	
Other Regulatory Liabilities:		
Deferred Income Taxes	\$ 818	asset lives
Minnesota Environmental Cost Recovery Rider Accrued Refund	139	12
Minnesota Transmission Cost Recovery Rider Accrued Refund	757	12
North Dakota Transmission Cost Recovery Rider Accrued Refund	2,163	24
Revenue for Rate Case Expenses Subject to Refund – Minnesota	919	16
South Dakota Environmental Cost Recovery Rider Accrued Refund	285	12
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up	132	24
Other	110	204
Total Other Regulatory Liabilities	\$ 5,323	
Net Other Regulatory Asset Position	\$ 141,223	

¹Costs subject to recovery without a rate of return.

²Amount eligible for recovery under an alternative revenue program which includes an incentive or rate of return.

The regulatory liability and asset related to Deferred Income Taxes results from changes in statutory tax rates accounted for in accordance with ASC Topic 740, *Income Taxes*.

The regulatory asset related to prior service costs and actuarial losses on pensions and other postretirement benefits represents benefit costs and actuarial losses subject to recovery through rates as they are expensed over the remaining service lives of active employees included in the plans. These unrecognized benefit costs and actuarial losses are required to be recognized as components of Accumulated Other Comprehensive Income in equity under ASC Topic 715, *Compensation—Retirement Benefits*, but are eligible for treatment as regulatory assets based on their probable recovery in future retail electric rates.

Conservation Improvement Program Costs and Incentives represent mandated conservation expenditures and incentives recoverable through retail electric rates.

The Accumulated ARO Accretion/Depreciation Adjustment will accrete and be amortized over the lives of property with asset retirement obligations.

All Deferred Marked-to-Market Losses recorded as of December 31, 2017 relate to forward purchases of energy scheduled for delivery through December 2020.

MISO Schedule 26/26A Transmission Cost Recovery Rider True-ups relate to the over/under collection of revenue based on

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comparison of the expected versus actual construction on eligible projects in the period. The true-ups also include the state jurisdictional portion of MISO Schedule 26/26A for regional transmission cost recovery that was included in the calculation of the state transmission riders and subsequently adjusted to reflect actual billing amounts in the schedule.

North Dakota Renewable Resource Rider Accrued Revenues relate to qualifying renewable resource costs incurred to serve North Dakota customers that have not been billed to North Dakota customers as of December 31, 2017.

North Dakota Deferred Rate Case Expenses Subject to Recovery relate to costs incurred in conjunction with OTP's current rate case in North Dakota currently being recovered over a 12-month period beginning with the establishment of interim rates in January 2018.

Minnesota Deferred Rate Case Expenses Subject to Recovery relate to costs incurred in conjunction with OTP's 2016 rate case in Minnesota currently being recovered over a 24-month period beginning with the establishment of interim rates in April 2016.

North Dakota Environmental Cost Recovery Rider Accrued Revenues relate to revenues earned on the North Dakota share of OTP's investments in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects and for reagent and emission allowances costs that are recoverable from North Dakota customers as of December 31, 2017.

Minnesota Energy Intensive Trade Exposed Rider Accrued Revenues relate to revenues recorded for fuel and purchased power costs reductions provided to customers in energy intensive trade exposed industries that are subject to recovery from other Minnesota customers.

The Minnesota Environmental Cost Recovery Rider Accrued Refund relates to amounts collected on the Minnesota share of OTP's investment in the Big Stone Plant AQCS project that are refundable to Minnesota customers as of December 31, 2017.

The Minnesota Transmission Cost Recovery Rider Accrued Refund relates to amounts collected for qualifying transmission system facilities and operating costs incurred to serve Minnesota customers that are refundable to Minnesota customers as of December 31, 2017.

The Minnesota Renewable Resource Rider Accrued Refund relates to amounts collected for qualifying renewable resource costs incurred to serve Minnesota customers that are refundable to Minnesota customers as of December 31, 2017.

The North Dakota Transmission Cost Recovery Rider Accrued Refund relates to amounts collected for qualifying transmission system facilities and operating costs incurred to serve North Dakota customers that are refundable to North Dakota customers as of December 31, 2017.

Revenue for Rate Case Expenses Subject to Refund – Minnesota relates to revenues collected under general rates to recover costs related to prior rate case proceedings in excess of the actual costs incurred, which are subject to refund over a 24-month period beginning with the establishment of interim rates in April 2016.

The South Dakota Environmental Cost Recovery Rider Accrued Refund relates to amounts collected on the South Dakota share of OTP's investments in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects that are refundable to South Dakota customers as of December 31, 2017.

The South Dakota Transmission Cost Recovery Rider Accrued Revenues relate to revenues earned on qualifying transmission system facilities that had not been billed to South Dakota customers as of December 31, 2016.

The South Dakota Transmission Cost Recovery Rider Accrued Refund relates to amounts collected for qualifying transmission system facilities and operating costs incurred to serve South Dakota customers that are refundable to South Dakota customers as of December 31, 2017.

If for any reason OTP ceases to meet the criteria for application of guidance under ASC 980 for all or part of its operations, the regulatory assets and liabilities that no longer meet such criteria would be removed from OTP's balance sheet and included in OTP's statement of income as an expense or income item in the period in which the application of guidance under ASC 980 ceases.

4. Common Shareholder's Equity

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OTP has issued and outstanding 100 shares of common stock with a par value of \$5 per share, with the sole holder of these shares being Otter Tail Corporation. Otter Tail Corporation made cash equity contributions to OTP totaling \$0 in 2017 and \$37,000,000 in 2016.

5. Retained Earnings and Dividend Restriction

OTP's credit agreements contain restrictions on the payment of cash dividends upon a default or event of default. An event of default would be considered to have occurred if OTP did not meet certain financial covenants. As of December 31, 2017 OTP was in compliance with these financial covenants. See note 7 for further information on the covenants.

Under the Federal Power Act, a public utility may not pay dividends from any funds properly included in a capital account. What constitutes "funds properly included in a capital account" is undefined in the Federal Power Act or the related regulations; however, the FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividend is not excessive and (3) there is no self-dealing on the part of corporate officials.

The MPUC indirectly limits the amount of dividends OTP can pay to Otter Tail Corporation by requiring an equity-to-total-capitalization ratio between 47.4% and 58.0% based on OTP's 2017 capital structure petition approved by order of the MPUC on September 1, 2017. As of December 31, 2017 OTP's equity-to-total-capitalization ratio including short-term debt was 51.4% and its net assets restricted from distribution totaled approximately \$471,000,000. Total capitalization for OTP cannot currently exceed \$1,178,024,000.

6. Commitments and Contingencies

Construction and Other Purchase Commitments

At December 31, 2017 OTP had commitments under contracts, including its share of construction program commitments, extending into 2019, of approximately \$41.0 million.

Electric Utility Capacity and Energy Requirements and Coal Purchase and Delivery Contracts

OTP has commitments for the purchase of capacity and energy requirements under agreements extending into 2041. OTP has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. OTP's current coal purchase agreements for Big Stone Plant and Coyote Station expire at the end of 2019 and 2040, respectively. OTP has an agreement with Cloud Peak Energy Resources LLC for the purchase of subbituminous coal for Hoot Lake Plant through December 31, 2023. OTP has no fixed minimum purchase requirements under the agreement, but all of Hoot Lake Plant's coal requirements for the period covered must be purchased under this agreement. The dollar amounts of OTP's estimated purchase requirements under this agreement are excluded from the table below because OTP has not committed to any minimum level of purchases under the agreement. Fuel clause adjustment mechanisms lessen the risk of loss from market price changes because they currently provide for recovery of most fuel costs. See table below for schedule of commitments.

Operating Leases

OTP has obligations to make future operating lease payments primarily related to land leases and coal rail-car leases. Rent expense from operations was \$2,540,000 for 2017 and \$2,577,000 for 2016.

The amounts of OTP's construction program and other commitments and commitments under capacity and energy agreements, coal and coal delivery contracts and operating leases as of December 31, 2017, are as follows:

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<i>(in thousands)</i>	Construction Program and Other Commitments	Capacity and Energy Requirements	Coal Purchase Commitments	Operating Leases
2018	\$ 27,538	\$ 24,424	\$ 26,021	\$ 1,838
2019	13,479	24,925	23,016	1,435
2020	--	24,844	22,102	1,436
2021	--	12,988	22,537	1,241
2022	--	11,827	22,300	761
Beyond 2022	--	154,310	527,520	8,644
Total	\$ 41,017	\$ 253,318	\$ 643,496	\$ 15,355

Contingencies

OTP had a \$2.7 million refund liability on its balance sheet as of December 31, 2016 representing its best estimate of the refund obligations that would arise, net of amounts that would be subject to recovery under state jurisdictional TCR riders, based on the likelihood of the FERC reducing the ROE component of the MISO Tariff and ordering MISO to refund amounts charged in excess of the lower rate. In the February and June 2017 MISO billings, MISO processed the refund of the FERC-ordered reduction in the MISO Tariff allowed ROE for the first 15-month refund period. The refund, in combination with a decision in the 2016 Minnesota general rate case that affected the Minnesota TCR rider, resulted in a reduction in OTP's accrued MISO Tariff ROE refund liability from \$2.7 million as of December 31, 2016 to \$1.6 million as of December 31, 2017.

Together with as many as 200 utilities, generators and power marketers, OTP participated in proceedings before the FERC regarding the calculation, assessment and implementation of MISO Revenue Sufficiency Guarantee (RSG) charges for entities participating in the MISO wholesale energy market since that market's start on April 1, 2005 until the conclusion of the proceedings on May 2, 2015. The proceedings fundamentally concerned MISO's application of its MISO RSG rate on file with the FERC to market participants, revisions to the RSG rate based on several FERC orders, and the FERC's decision to not resettle the markets based on MISO application of the RSG rate to market participants. Several of the FERC's orders are on review in a set of consolidated cases before the D.C. Circuit. The consolidated petitions at the D.C. Circuit involve multiple petitioners and intervenors. OTP is an intervenor in these cases. Final briefs were filed on January 26, 2018. Oral arguments will occur in the spring of 2018. A final decision is not expected until late in 2018. MISO has not made available past billing or resettlement data necessary for determining amounts that might be payable if the FERC's decisions are reversed. Therefore, OTP cannot estimate its exposure at this time from a final order reversing the relevant FERC orders, which could have an adverse effect on OTP's results of operations.

Contingencies, by their nature, relate to uncertainties that require OTP's management to exercise judgment both in assessing the likelihood a liability has been incurred as well as in estimating the amount of potential loss. The most significant contingencies that could potentially impact OTP's financial statements are those related to environmental remediation and litigation matters, but no estimates for potential losses have been made at this time, including any liability for RSG charges.

In 2014 the Environmental Protection Agency (EPA) published both proposed standards of performance for carbon dioxide (CO₂) emissions from new, reconstructed and modified fossil fuel-fired power plants (New Source Performance Standards), and proposed CO₂ emission guidelines for existing fossil fuel-fired power plants (the Clean Power Plan) under section 111 of the Clean Air Act. The EPA published final rules for each of these proposals on October 23, 2015. Both rules were challenged on legal grounds. On February 9, 2016 the U.S. Supreme Court granted a stay of the Clean Power Plan, pending disposition of petitions for review in the D.C. Circuit. The D.C. Circuit heard oral argument on challenges to the Clean Power Plan on September 27, 2016 before the full court, and a decision was expected in the first half of 2017. However, pursuant to Executive Order 13783, Promoting Energy Independence and Economic Growth, the EPA was directed to consider suspending, revising or rescinding the CO₂ rules discussed above. Thereafter, the EPA issued notices in the Federal Register of its intent to review these rules pursuant to the Executive Order, and it filed motions to stay the pending litigation. The D.C. Circuit subsequently issued orders holding in abeyance the appeals of both the New Source Performance Standards and the Clean Power Plan, pending EPA review. On October 16, 2017 the EPA published a proposed rule to rescind the Clean Power Plan. Therefore, there is uncertainty regarding the future of both rules.

Other

OTP is a party to litigation and regulatory enforcement matters arising in the normal course of business. OTP regularly analyzes current information and, as necessary, provides accruals for liabilities that are probable of occurring and that can be reasonably

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estimated. OTP believes the effect on its results of operations, financial position and cash flows, if any, for the disposition of all matters pending as of December 31, 2017 will not be material.

7. Short-Term and Long-Term Borrowings

Short-Term Debt

The following table presents the status of OTP's line of credit as of December 31, 2017 and December 31, 2016:

<i>(in thousands)</i>	Line Limit	In Use on December 31, 2017	Restricted Due to Outstanding Letters of Credit	Available on December 31, 2017	Available on December 31, 2016
OTP Credit Agreement	\$ 170,000	\$ 112,371	\$ 300	\$ 57,329	\$ 127,067

Under the OTP Credit Agreement (as defined below), the maximum amount of debt outstanding in 2017 was \$112,371,000 on December 29, 2017 and the average daily balance of debt outstanding during 2017 was \$69,391,000. The weighted average interest rate paid on debt outstanding under the OTP Credit Agreement during 2017 was 2.4% compared with 1.8% in 2016. The weighted average interest rate on OTP's short-term debt outstanding on December 31, 2017 was 2.7%.

On October 29, 2012 OTP entered into a Second Amended and Restated Credit Agreement (the OTP Credit Agreement), providing for an unsecured \$170 million revolving credit facility that may be increased to \$250 million on the terms and subject to the conditions described in the OTP Credit Agreement. On October 31, 2017 the OTP Credit Agreement was amended to extend its expiration date by one year from October 29, 2021 to October 31, 2022. OTP can draw on this credit facility to support the working capital needs and other capital requirements of its operations, including letters of credit in an aggregate amount not to exceed \$50 million outstanding at any time. Borrowings under this line of credit bear interest at LIBOR plus 1.25%, subject to adjustment based on the ratings of OTP's senior unsecured debt or the issuer rating if a rating is not provided for the senior unsecured debt. OTP is required to pay commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The OTP Credit Agreement contains a number of restrictions on the business of OTP, including restrictions on its ability to merge, sell assets, make investments, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The OTP Credit Agreement also contains affirmative covenants and events of default, and financial covenants as described below under the heading "Financial Covenants." The OTP Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. OTP's obligations under the OTP Credit Agreement are not guaranteed by any other party.

Long-Term Debt

2018 Note Purchase Agreement

On November 14, 2017, OTP entered into a Note Purchase Agreement (the 2018 Note Purchase Agreement) with the purchasers named therein, pursuant to which OTP agreed to issue to the purchasers, in a private placement transaction, \$100 million aggregate principal amount of OTP's 4.07% Series 2018A Senior Unsecured Notes due February 7, 2048 (the 2018 Notes). The 2018 Notes were issued on February 7, 2018. Proceeds from the 2018 Notes were used to repay \$100 million in outstanding borrowings under the OTP Credit Agreement.

OTP may prepay all or any part of the Notes (in an amount not less than 10% of the aggregate principal amount of the Notes then outstanding in the case of a partial prepayment) at 100% of the principal amount so prepaid, together with unpaid accrued interest and a make-whole amount; provided that if no default or event of default exists under the Note Purchase Agreement, any prepayment made by OTP of all of the Notes then outstanding on or after August 7, 2047 will be made without any make-whole amount. The 2018 Note Purchase Agreement also requires OTP to offer to prepay all outstanding Notes at 100% of the principal amount together with unpaid accrued interest in the event of a Change of Control (as defined in the 2018 Note Purchase Agreement) of OTP.

The 2018 Note Purchase Agreement contains a number of restrictions on the business of OTP. These include restrictions on OTP's abilities to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The 2018 Note Purchase Agreement also contains other negative covenants and events of default, as well as certain financial covenants as described below under the heading "Financial Covenants." The 2018 Note Purchase Agreement does not

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include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. The 2018 Note Purchase Agreement includes a "most favored lender" provision generally requiring that in the event the OTP Credit Agreement or any renewal, extension or replacement thereof, at any time contains any financial covenant or other provision providing for limitations on interest expense and such a covenant is not contained in the 2018 Note Purchase Agreement under substantially similar terms or would be more beneficial to the holders of the 2018 Notes than any analogous provision contained in the 2018 Note Purchase Agreement (Additional Covenant), then unless waived by the Required Holders (as defined in the 2018 Note Purchase Agreement), the Additional Covenant will be deemed to be incorporated into the 2018 Note Purchase Agreement. The 2018 Note Purchase Agreement also provides for the amendment, modification or deletion of an Additional Covenant if such Additional Covenant is amended or modified under or deleted from the OTP Credit Agreement, provided that no default or event of default has occurred and is continuing.

2013 Note Purchase Agreement

On August 14, 2013 OTP entered into a Note Purchase Agreement (the 2013 Note Purchase Agreement) with the purchasers named therein pursuant to which OTP agreed to issue to the purchasers, in a private placement transaction, \$60 million aggregate principal amount of OTP's 4.68% Series A Senior Unsecured Notes due February 27, 2029 (the Series A Notes) and \$90 million aggregate principal amount of OTP's 5.47% Series B Senior Unsecured Notes due February 27, 2044 (the Series B Notes and, together with the Series A Notes, the Notes). The Notes were issued on February 27, 2014.

The 2013 Note Purchase Agreement states that OTP may prepay all or any part of the Notes (in an amount not less than 10% of the aggregate principal amount of the Notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount, provided that if no default or event of default under the 2013 Note Purchase Agreement exists, any optional prepayment made by OTP of (i) all of the Series A Notes then outstanding on or after November 27, 2028 or (ii) all of the Series B Notes then outstanding on or after November 27, 2043, will be made at 100% of the principal prepaid but without any make-whole amount. In addition, the 2013 Note Purchase Agreement states OTP must offer to prepay all of the outstanding Notes at 100% of the principal amount together with unpaid accrued interest in the event of a Change of Control (as defined in the 2013 Note Purchase Agreement) of OTP.

The 2013 Note Purchase Agreement contains a number of restrictions on the business of OTP, including restrictions on OTP's ability to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The 2013 Note Purchase Agreement also contains affirmative covenants and events of default, as well as certain financial covenants as described below under the heading "Financial Covenants." The 2013 Note Purchase Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. The 2013 Note Purchase Agreement includes a "most favored lender" provision generally requiring that in the event the OTP Credit Agreement or any renewal, extension or replacement thereof, at any time contains any financial covenant or other provision providing for limitations on interest expense and such a covenant is not contained in the 2013 Note Purchase Agreement under substantially similar terms or would be more beneficial to the holders of the Notes than any analogous provision contained in the 2013 Note Purchase Agreement (Additional Covenant), then unless waived by the Required Holders (as defined in the 2013 Note Purchase Agreement), the Additional Covenant will be deemed to be incorporated into the 2013 Note Purchase Agreement. The 2013 Note Purchase Agreement also provides for the amendment, modification or deletion of an Additional Covenant if such Additional Covenant is amended or modified under or deleted from the OTP Credit Agreement, provided that no default or event of default has occurred and is continuing.

2007 and 2011 Note Purchase Agreements

On December 1, 2011, OTP issued \$140 million aggregate principal amount of its 4.63% Senior Unsecured Notes due December 1, 2021 pursuant to a Note Purchase Agreement dated as of July 29, 2011 (the 2011 Note Purchase Agreement). OTP also has outstanding its \$122 million senior unsecured notes issued in three series consisting of \$30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022; \$42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027; and \$50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037 (collectively, the 2007 Notes). The 2007 Notes were issued pursuant to a Note Purchase Agreement dated as of August 20, 2007 (the 2007 Note Purchase Agreement). On August 21, 2017 OTP used borrowings under the OTP Credit Agreement to retire the \$33 million 5.95%, Series A Senior Unsecured Notes, which had been issued under the 2007 Note Purchase Agreement and matured on August 20, 2017.

The 2011 Note Purchase Agreement and the 2007 Note Purchase Agreement each states that OTP may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of

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a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. The 2011 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require OTP to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the 2011 Note Purchase Agreement. The 2011 Note Purchase Agreement and the 2007 Note Purchase Agreement each also states that OTP must offer to prepay all of the outstanding notes issued thereunder at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of OTP. The note purchase agreements contain a number of restrictions on OTP, including restrictions on OTP's ability to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The note purchase agreements also include affirmative covenants and events of default, and certain financial covenants as described below under the heading "Financial Covenants."

The aggregate amounts of maturities on bonds outstanding and other long-term obligations at December 31, 2017 for each of the next five years are:

<i>(in thousands)</i>	2018	2019	2020	2021	2022
Aggregate Amounts of Debt Maturities	\$ --	\$ --	\$ --	\$ 140,000	\$ 30,000

Financial Covenants

OTP was in compliance with the financial covenants in their debt agreements as of December 31, 2017.

No Credit or Note Purchase Agreement contains any provisions that would trigger an acceleration of the related debt as a result of changes in the credit rating levels assigned to the related obligor by rating agencies.

OTP's borrowing agreements are subject to certain financial covenants. Specifically:

- Under the OTP Credit Agreement, OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00.
- Under the 2007 Note Purchase Agreement and the 2011 Note Purchase Agreement, OTP may not permit the ratio of its Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, in each case as provided in the related borrowing agreement, and OTP may not permit its Priority Debt to exceed 20% of its Total Capitalization, as provided in the related agreement.
- Under the 2013 Note Purchase Agreement and the 2018 Note Purchase Agreement, OTP may not permit its Interest-bearing Debt to exceed 60% of Total Capitalization and may not permit its Priority Indebtedness to exceed 20% of its Total Capitalization, in each case as provided in the related agreement. OTP had no Priority Indebtedness outstanding as of December 31, 2017.

8. Pension Plan and Other Postretirement Benefits

Pension Plan

OTP's noncontributory funded pension plan (the Plan) covers substantially all OTP nonunion employees hired prior to September 1, 2006, and all union employees of OTP hired prior to November 1, 2013, excluding Coyote Station employees. Coyote Station employees hired before January 1, 2009 are covered under the Plan. The Plan provides 100% vesting after five vesting years of service and for retirement compensation at age 65, with reduced compensation in cases of retirement prior to age 62. OTP reserves the right to discontinue the Plan but no change or discontinuance may affect the pensions theretofore vested.

The pension plan has a trustee who is responsible for pension payments to retirees and a separate pension fund manager responsible for managing the Plan's assets. An independent actuary assists in performing the necessary actuarial valuations for the Plan.

The Plan assets consist of common stock and bonds of public companies, U.S. government securities, cash and cash equivalents and alternative investments. None of the Plan assets are invested in common stock or debt securities of OTP or Otter Tail Corporation.

Components of net periodic pension benefit cost:

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<i>(in thousands)</i>	2017	2016
Service Cost–Benefit Earned During the Period	\$ 5,494	\$ 5,386
Interest Cost on Projected Benefit Obligation	13,800	13,854
Expected Return on Assets	(18,768)	(18,987)
Amortization of Prior-Service Cost from Regulatory Asset	120	189
Amortization of Net Actuarial Loss from Regulatory Asset	5,090	5,153
Net Periodic Pension Cost	\$ 5,736	\$ 5,595

Allocation of Costs:	2017	2016
Costs included in OTP Capital Expenditures	\$ 1,142	\$ 1,048
Costs included in Electric Operation and Maintenance Expenses	4,594	4,547

Weighted average assumptions used to determine net periodic pension cost for the year ended December 31:

	2017	2016
Discount Rate	4.60%	4.76%
Long-Term Rate of Return on Plan Assets	7.50%	7.75%
Rate of Increase in Future Compensation Level	3.00%	3.13%

The following table presents amounts recognized in OTP's balance sheets as of December 31:

<i>(in thousands)</i>	2017	2016
Regulatory Assets:		
Unrecognized Prior Service Cost	\$ 21	\$ 141
Unrecognized Actuarial Loss	99,360	98,039
Total Regulatory Assets	\$ 99,381	\$ 98,180
Noncurrent Liability	\$ 65,782	\$ 58,845

Funded status as of December 31:

<i>(in thousands)</i>	2017	2016
Accumulated Benefit Obligation	\$(308,509)	\$(274,660)
Projected Benefit Obligation	\$(344,253)	\$(307,086)
Fair Value of Plan Assets	278,471	248,241
Funded Status	\$ (65,782)	\$ (58,845)

The following tables provide a reconciliation of the changes in the OTP portion of the fair value of the Plan's assets and the Plan's benefit obligations over the two-year period ended December 31, 2017:

<i>(in thousands)</i>	2017	2016
Reconciliation of OTP's Portion of the Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	\$ 248,241	\$ 227,798
Actual Return on Plan Assets	43,312	23,404
Discretionary Company Contributions	--	10,000
Benefit Payments	(13,082)	(12,961)
Fair Value of Plan Assets at December 31	\$ 278,471	\$ 248,241
Estimated Asset Return	17.8%	10.1%
Reconciliation of OTP's Portion of the Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	\$ 307,086	\$ 295,171
Service Cost	5,494	5,386
Interest Cost	13,800	13,854
Benefit Payments	(13,082)	(12,961)
Actuarial Loss	30,955	5,636
Projected Benefit Obligation at December 31	\$ 344,253	\$ 307,086

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Weighted average assumptions used to determine benefit obligations at December 31:

	2017	2016
Discount Rate	3.90%	4.60%
Rate of Increase in Future Compensation Level:		
All participants – prior to 2017		3.00%
Participants to Age 39	4.50%	
Participants Age 40 to Age 49	3.50%	
Participants Age 50 and Older	2.75%	

The assumed rate of return on pension fund assets used for the determination of 2018 net periodic pension cost is 7.50%. The assumed long-term rate of return on plan assets is based primarily on asset category studies using historical market return and volatility data with forward looking estimates based on existing financial market conditions and forecasts of capital markets. Modest excess return expectations versus some market indices are incorporated into the return projections based on the actively managed structure of the investment programs and their records of achieving such returns historically. The rate of return on plan asset assumptions are reviewed annually. The assumptions are largely based on the asset category rate-of-return assumptions developed annually with the pension plan investment advisors, as well as input from actuaries who work with the pension plan and benchmarking to peer companies with similar asset allocation strategies.

Market-related value of plan assets—The expected return on plan assets is determined based on the expected long-term rate of return on plan assets and the market-related value of plan assets.

The actuarial determination of pension plan expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation calculation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related valuation calculation recognizes gains or losses over a five-year period, the future value of the market-related assets will be impacted as previously deferred gains or losses are recognized.

Measurement Dates:	2017	2016
Net Periodic Pension Cost	January 1, 2017 January 1, 2017 projected to December 31, 2017	January 1, 2016 January 1, 2016 projected to December 31, 2016
End of Year Benefit Obligations	December 31, 2017	December 31, 2016
Market Value of Assets		

The estimated amounts of unrecognized net actuarial losses and prior service costs to be amortized from regulatory assets into the net periodic pension cost in 2018 are:

<i>(in thousands)</i>	2018
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	\$ 16
Amortization of Unrecognized Actuarial Loss	7,142
Total Estimated Amortization	\$ 7,158

Cash flows—OTP had no minimum funding requirement as of December 31, 2017 but made discretionary plan contributions of \$20 million as of February 2018.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid out from plan assets:

<i>(in thousands)</i>	2018	2019	2020	2021	2022	Years 2023-2027
	\$14,245	\$14,878	\$15,515	\$16,180	\$16,877	\$92,981

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The following objectives guide the investment strategy of the Plan:

- The assets of the Plan will be invested in accordance with all applicable laws in a manner consistent with fiduciary standards including Employee Retirement Income Security Act standards (if applicable). Specifically:
 - The safeguards and diversity that a prudent investor would adhere to must be present in the investment program.
 - All transactions undertaken on behalf of the Plan must be in the best interest of plan participants and their beneficiaries.
- The primary objective of the Plan is to provide a source of retirement income for its participants and beneficiaries.
- The near-term primary financial objective of the Plan is to improve the funded status of the Plan.
- A secondary financial objective is to minimize pension funding and expense volatility where possible.

The asset allocation strategy developed by the Retirement Plans Administration Committee (the Committee) is based on the current needs of the Plan and the objectives listed above. An asset/liability review is conducted annually or as often as necessary to assess the impact of various asset allocations on funded status and other financial variables. The current needs of the Plan, the overall investment objectives above, the investment preferences and risk tolerance of the Committee and the desired degree of diversification suggest the need for an investment allocation including multiple asset classes.

The asset allocation in the table below contains guideline percentages, at market value, of the total Plan invested in various asset classes. The Permitted Range is a guide and will at times not reflect the actual asset allocation as this will be dictated by market conditions, the independent actions of the Committee and/or Investment Managers and required cash flows to and from the Plan. The Permitted Range anticipates this fluctuation and provides flexibility for the Investment Managers' portfolios to vary around the target without the need for immediate rebalancing. The Investment Manager will proactively monitor the asset allocation and will direct the purchases and sales to remain within the stated ranges.

The policy of the Plan is to invest assets in accordance with the allocations shown below:

Asset Class / PBO Funded Status	Permitted Range				
	< 85% PBO	>=85% PBO	>=90% PBO	>=95% PBO	>=100% PBO
Equity	39% - 59%	34% - 54%	24% - 44%	14% - 34%	0% - 20%
Investment Grade Fixed Income	22% - 42%	30% - 50%	40% - 60%	53% - 73%	70% - 100%
Below Investment Grade Fixed Income*	0% - 15%	0% - 15%	0% - 15%	0% - 10%	0% - 10%
Other**	5% - 20%	5% - 20%	5% - 20%	0% - 15%	0% - 15%

* Includes (but not limited to) High Yield Bond Fund and Emerging Markets Debt funds.

** Other category may include cash, alternatives, and/or other investment strategies that may be classified other than equity or fixed income, such as the Dynamic Asset Allocation fund.

OTP's pension plan asset allocations at December 31, 2017 and 2016, by asset category are as follows:

Asset Allocation	2017	2016
Large Capitalization Equity Securities	23.5%	21.4%
International Equity Securities	18.1%	22.0%
Small and Mid-Capitalization Equity Securities	8.7%	9.0%
Emerging Markets Equity Fund	5.5%	0.0%
SEI Dynamic Asset Allocation Fund	5.0%	5.4%
Equity Securities	60.8%	57.8%
Fixed-Income Securities and Cash	35.2%	34.3%
Other – SEI Energy Debt Collective Fund	4.0%	4.1%
Other – SEI Special Situation Collective Investment Trust	0.0%	3.8%
	100.0%	100.0%

The following table presents OTP's pension fund assets measured at fair value and included in Level 1 of the fair value hierarchy and assets measured using the net asset value (NAV) practical expedient to fair valuation as of December 31:

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<i>(in thousands)</i>	2017	2016
Assets in Level 1 of the Fair Value Hierarchy	\$ 267,423	\$ 228,680
SEI Energy Debt Collective Fund at NAV	11,048	10,190
SEI Special Situation Collective Investment Trust Fund at NAV	--	9,371
Total Assets	\$ 278,471	\$ 248,241

Fair Value Measurements of Pension Fund Assets

ASC 715, *Compensation – Retirement Benefits*, requires disclosures about pension plan assets identified by the three levels of the fair value hierarchy established by ASC 820-10-35.

The following table presents OTP's pension fund assets measured at fair value and included in Level 1 of the fair value hierarchy as of December 31:

<i>(in thousands)</i>	2017	2016
Large Capitalization Equity Securities Mutual Fund	\$ 65,339	\$ 53,175
International Equity Securities Mutual Funds	50,397	54,574
Small and Mid-Capitalization Equity Securities Mutual Fund	24,252	22,459
Emerging Markets Equity Fund	15,444	--
SEI Dynamic Asset Allocation Mutual Fund	14,026	13,295
Fixed Income Securities Mutual Funds	97,964	85,174
Cash Management – Money Market Fund	1	3
Total Assets	\$ 267,423	\$ 228,680

The investments held by the SEI Energy Debt Collective Fund on December 31, 2017 and 2016 consist mainly of below investment grade high yielding bonds and loans of U.S. energy companies which trade at a discount to fair value. Redemptions are allowed semi-annually with a 95-day notice period, subject to fund director consent and certain gate, holdback and suspension restrictions. Subscriptions are allowed monthly with a three-year lock up on subscriptions. Fund assets totaling \$10.0 million were invested in the SEI Energy Debt Fund in July 2015. The fund's assets are valued in accordance with valuations reported by the fund's sub-advisor or the fund's underlying investments or other independent third party sources, although SEI in its discretion may use other valuation methods, subject to compliance with ERISA (as applicable). The fund's assets are valued as of the close of business on the last business day of each calendar month and are available 30 days after the end of a calendar quarter. On an annual basis, as determined by the investment manager in its sole discretion, an independent valuation agent is retained to provide a valuation of the illiquid assets of the fund and of any other asset of the fund, as determined by the investment manager in its sole discretion. Otter Tail Corporation reviews and verifies the reasonableness of the year-end valuations.

Executive Survivor and Supplemental Retirement Plan (ESSRP)

The ESSRP is an unfunded, nonqualified benefit plan for Otter Tail Corporation and OTP executive officers and certain key management employees. The ESSRP provides defined benefit payments to these employees on their retirements for life or to their beneficiaries on their deaths for a 15-year postretirement period. There are no plan assets in this nonqualified benefit plan due to the nature of the plan.

The following table lists components of net periodic pension benefit cost for the year ended December 31:

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<i>(in thousands)</i>	2017	2016
Service Cost–Benefit Earned During the Period	\$ 94	\$ 87
Interest Cost on Projected Benefit Obligation	763	782
Amortization of Prior Service Cost:		
From Regulatory Asset	16	16
From Other Comprehensive Income ¹	15	15
Amortization of Net Actuarial Loss:		
From Regulatory Asset	285	293
From Other Comprehensive Income ¹	265	272
Net Periodic Pension Cost²	\$ 1,438	\$ 1,465

¹Amortization of Prior Service Costs and Net Actuarial Loss from Other Comprehensive Income Charged to Electric Operation and Maintenance Expenses

²ESSRP costs are not capitalized

Weighted average assumptions used to determine net periodic pension cost for the year ended December 31:

	2017	2016
Discount Rate	4.60%	4.76%
Rate of Increase in Future Compensation Level	3.00%	3.25%

The following table presents amounts recognized in OTP's balance sheets as of December 31:

<i>(in thousands)</i>	2017	2016
Regulatory Assets:		
Unrecognized Prior Service Cost	\$ 40	\$ 58
Unrecognized Actuarial Loss	3,229	2,890
Total Regulatory Assets	\$ 3,269	\$ 2,948
Projected Benefit Obligation Liability – Net Amount Recognized	\$(18,380)	\$(17,263)
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	\$ 40	\$ 54
Unrecognized Actuarial Loss	3,229	2,682
Total Accumulated Other Comprehensive Loss	\$ 3,269	\$ 2,736

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's projected benefit obligations over the two-year period ended December 31, 2017 and a statement of the funded status as of December 31 of both years:

<i>(in thousands)</i>	2017	2016
Reconciliation of OTP's Portion of the Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	\$ --	\$ --
Actual Return on Plan Assets	--	--
Employer Contributions	1,175	1,188
Benefit Payments	(1,175)	(1,188)
Fair Value of Plan Assets at December 31	\$ --	\$ --
Reconciliation of OTP's Portion of the Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	\$ 17,263	\$ 17,107
Service Cost	94	87
Interest Cost	763	782
Benefit Payments	(1,175)	(1,188)
Actuarial Loss	1,435	475
Projected Benefit Obligation at December 31	\$ 18,380	\$ 17,263

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Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Weighted average assumptions used to determine benefit obligations at December 31:

	2017	2016
Discount Rate	3.85%	4.60%
Rate of Increase in Future Compensation Level	2.75%	3.00%

The estimated amounts of unrecognized net actuarial losses and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic pension cost for the ESSRP in 2018 are:

<i>(in thousands)</i>	2018
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	\$ 16
Amortization of Unrecognized Actuarial Loss	267
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	16
Amortization of Unrecognized Actuarial Loss	267
Total Estimated Amortization	\$ 566

Cash flows—The ESSRP is unfunded and has no assets; contributions are equal to the benefits paid to plan participants. The following benefit payments, which reflect future service, as appropriate, are expected to be paid:

<i>(in thousands)</i>	2018	2019	2020	2021	2022	Years 2023-2027
	\$1,373	\$1,416	\$1,380	\$1,339	\$1,297	\$5,828

Other Postretirement Benefits

OTP provides a portion of health insurance and life insurance benefits for retired OTP employees. Substantially all of OTP's electric utility employees may become eligible for health insurance benefits if they reach age 55 and have 10 years of service. There are no plan assets. The following table lists components of net periodic postretirement benefit cost for the year ended December 31:

<i>(in thousands)</i>	2017	2016
Service Cost—Benefit Earned During the Period	\$ 1,391	\$ 1,270
Interest Cost on Projected Benefit Obligation	2,647	2,443
Amortization of Prior Service Cost from Regulatory Asset	(4)	134
Amortization of Net Actuarial Loss from Regulatory Asset	936	379
Net Periodic Postretirement Benefit Cost	\$ 4,970	\$ 4,226
Effect of Medicare Part D Subsidy	\$ (547)	\$ (901)

Allocation of Cost:	2017	2016
Cost included in OTP Capital Expenditures	\$ 989	\$ 792
Cost included in Electric Operation and Maintenance Expenses	3,981	3,433

Weighted average assumptions used to determine net periodic postretirement benefit cost for the year ended December 31:

	2017	2016
Discount Rate	4.46%	4.57%

The following table presents amounts recognized in OTP's balance sheets as of December 31:

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Otter Tail Power Company		12/31/2017	2017/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

<i>(in thousands)</i>	2017	2016
Regulatory Asset:		
Unrecognized Prior Service Cost	\$ --	\$ (4)
Unrecognized Net Actuarial Loss	18,927	13,586
Net Regulatory Asset	\$ 18,927	\$ 13,582
Projected Benefit Obligation Liability – Net Amount Recognized	\$ (68,100)	\$ (61,070)

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's projected benefit obligations over the two-year period ended December 31, 2017:

<i>(in thousands)</i>	2017	2016
Reconciliation of OTP's Portion of the Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	\$ --	\$ --
Actual Return on Plan Assets	--	--
Company Contributions	3,284	2,832
Benefit Payments (Net of Medicare Part D Subsidy)	(6,512)	(5,888)
Participant Premium Payments	3,228	3,056
Fair Value of Plan Assets at December 31	\$ --	\$ --
Reconciliation of OTP's Portion of the Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	\$ 61,070	\$ 47,512
Service Cost (Net of Medicare Part D Subsidy)	1,391	1,270
Interest Cost (Net of Medicare Part D Subsidy)	2,647	2,443
Benefit Payments (Net of Medicare Part D Subsidy)	(6,512)	(5,888)
Participant Premium Payments	3,228	3,056
Actuarial Loss	6,276	12,677
Projected Benefit Obligation at December 31	\$ 68,100	\$ 61,070

Weighted average assumptions used to determine benefit obligations at December 31:

	2017	2016
Discount Rate	3.81%	4.46%

Assumed healthcare cost-trend rates as of December 31:

	2017	2016
Healthcare Cost-Trend Rate Assumed for Next Year Pre-65	5.85%	6.01%
Healthcare Cost-Trend Rate Assumed for Next Year Post-65	6.03%	6.23%
Rate to Which the Cost-Trend Rate is Assumed to Decline	4.50%	4.50%
Year the Rate Reaches the Ultimate Trend Rate	2038	2038

Assumed healthcare cost-trend rates have a significant effect on the amounts reported for healthcare plans. A one-percentage-point change in assumed healthcare cost-trend rates for 2017 would have the following effects:

<i>(in thousands)</i>	1 Point Increase	1 Point Decrease
Effect on the Postretirement Benefit Obligation	\$ 9,078	\$ (7,507)
Effect on Total of Service and Interest Cost	\$ 714	\$ (587)
Effect on Expense	\$ 1,551	\$ (1,464)

Measurement Dates:	2017	2016
Net Periodic Postretirement Benefit Cost	January 1, 2017	January 1, 2016
End of Year Benefit Obligations	January 1, 2017 projected to December 31, 2017	January 1, 2016 projected to December 31, 2016

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NOTES TO FINANCIAL STATEMENTS (Continued)			

The estimated net amounts of unrecognized accumulated actuarial losses to be amortized from regulatory assets into the net periodic postretirement benefit cost in 2018 is \$1,649,000.

Cash flows—OTP expects to contribute \$3.9 million net of expected employee contributions for the payment of retiree medical benefits and Medicare Part D subsidy receipts in 2018. OTP expects to receive a Medicare Part D subsidy from the Federal government of approximately \$406,000 in 2018. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

<i>(in thousands)</i>	Years					
	2018	2019	2020	2021	2022	2023-2027
	\$3,890	\$4,009	\$4,033	\$4,116	\$4,223	\$20,583

401K Plan

OTP has a 401K plan for the benefit of all its employees. Contributions made to this plan by OTP totaled \$2,381,000 for 2017 and \$2,229,000 for 2016.

Employee Stock Ownership Plan

OTP has a stock ownership plan for the benefit of all its employees. Contributions made by OTP were \$612,000 for 2017 and \$647,000 for 2016.

9. Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value:

Cash Equivalents—The carrying amount approximates fair value because of the short-term maturity of those instruments.

Short-Term Debt—The carrying amount approximates fair value because the debt obligations are short-term and the balance outstanding as of December 31, 2017 and 2016 under the OTP Credit Agreement was subject to a variable interest rate of LIBOR plus 1.25%, which approximates a market rate.

Long-Term Debt including Current Maturities—The fair value of OTP's long-term debt is estimated based on the current market indications of rates available to OTP for the issuance of debt. The fair value measurements of OTP's long-term debt issues fall into level 2 of the fair value hierarchy set forth in ASC 820.

<i>(in thousands)</i>	December 31, 2017		December 31, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Short-term Investments	\$ 22	\$ 22	\$ 22	\$ 22
Short-Term Debt	(112,371)	(112,371)	(42,883)	(42,883)
Long-Term Debt including Current Maturities	(412,000)	(469,180)	(445,000)	(495,429)

10. Property, Plant and Equipment

<i>(in thousands)</i>	December 31,	December 31,	Service Life Range	
	2017	2016	<i>(years)</i>	
			Low	High
Electric Plant				
Production	\$ 897,732	\$ 891,330	9	82
Transmission	500,352	410,679	42	70
Distribution	482,867	466,285	5	68
General	100,067	92,063	5	50
Electric Plant in Service	1,981,018	1,860,357		
Construction Work in Progress	132,556	149,997		
Total Plant	2,113,574	2,010,354		
Less Accumulated Depreciation and Amortization	745,531	703,061		
Net Plant	\$ 1,368,043	\$ 1,307,293		

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NOTES TO FINANCIAL STATEMENTS (Continued)			

11. Income Taxes

The total income tax expense differs from the amount computed by applying the federal income tax rate (35% in 2017 and 2016) to net income before total income tax expense for the following reasons:

<i>(in thousands)</i>	2017	2016
Tax Computed at Federal Statutory Rate	\$ 23,261	\$ 23,168
Increases (Decreases) in Tax from:		
State Income Taxes Net of Federal Income Tax Benefit	2,769	2,499
Differences Reversing in Excess of Federal Rates	551	77
Federal Production Tax Credit	(7,527)	(7,175)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(850)	(850)
Dividend Received/Paid Deduction	(509)	(537)
Investment Tax Credit Amortization	(164)	(350)
Allowance for Funds Used During Construction - Equity	(322)	(280)
Effect of TCJA	458	--
Permanent and Other Differences	(654)	(186)
Total Income Tax Expense	\$ 17,013	\$ 16,366
Overall Effective Federal and State Income Tax Rate	25.6%	24.7%
Income Tax Expense Includes the Following:		
Current Federal Income Taxes	\$ (291)	\$ (57)
Current State Income Taxes	784	604
Deferred Federal Income Taxes	21,583	20,953
Deferred State Income Taxes	3,478	3,241
Federal Production Tax Credit	(7,527)	(7,175)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(850)	(850)
Investment Tax Credit Amortization	(164)	(350)
Total	\$ 17,013	\$ 16,366
Total Income Before Income Taxes	\$ 66,459	\$ 66,195

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
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NOTES TO FINANCIAL STATEMENTS (Continued)			

OTP's deferred tax assets and liabilities were composed of the following on December 31:

<i>(in thousands)</i>	2017	2016
Deferred Tax Assets		
Federal Production Tax Credits (PTCs)	\$ 40,640	\$ 33,113
North Dakota Wind Tax Credits	35,794	40,869
Benefit Liabilities	18,776	27,238
Differences Related to Property	5,420	8,255
Net Operating Loss Carryforward	845	9,035
Vacation Accrual	1,142	1,727
Other	560	6,467
Investment Tax Credits	515	818
Total Deferred Tax Assets	\$ 103,692	\$ 127,522
Deferred Tax Liabilities		
Differences Related to Property	\$(179,929)	\$(323,012)
Excess Tax Over Book Pension	(14,077)	(15,509)
North Dakota Wind Tax Credits	(6,926)	(11,543)
AQCS Section 169	(3,263)	(2,645)
Regulatory Asset	(2,279)	(3,624)
Impact of State Net Operating Losses on Federal Taxes	(487)	(894)
Renewable Resource Rider Accrued Revenue	(164)	(955)
Other	1,010	(3,234)
Total Deferred Tax Liabilities	\$(206,116)	\$(361,416)
Deferred Income Taxes	\$(102,424)	\$(233,894)

Federal PTCs are earned as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes. OTP's kwh generation from its wind turbines eligible for PTCs increased 4.4% in 2017 compared with 2016. North Dakota wind energy credits are based on dollars invested in qualifying facilities and are being recognized on a straight-line basis over 25 years. Schedule of expiration of tax credits and tax net operating losses available as of December 31, 2017:

<i>(in thousands)</i>	Amount	2029-37	2038-43
Federal Net Operating Losses	\$ 845	\$ 845	\$ --
Federal Tax Credits	40,625	40,625	--
State Net Operating Losses	2,301	2,301	--
State Tax Credits	32,962	--	32,962

The following table summarizes the activity related to OTP's unrecognized tax benefits:

<i>(in thousands)</i>	2017	2016
Balance on January 1	\$ 411	\$ 468
(Decreases) Increases Related to Tax Positions for Prior Years	(291)	40
Increases Related to Tax Positions for Current Year	--	--
Uncertain Positions Resolved During Year	--	(97)
Balance on December 31	\$ 120	\$ 411

The balance of unrecognized tax benefits as of December 31, 2017 would reduce the OTP's effective tax rate if recognized. The total amount of unrecognized tax benefits as of December 31, 2017 is not expected to change significantly within the next 12 months. There was no amount accrued for interest on tax uncertainties as of December 31, 2017.

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NOTES TO FINANCIAL STATEMENTS (Continued)			

Otter Tail Corporation and its subsidiaries, including OTP, file a consolidated U.S. federal income tax return and various state income tax returns. As of December 31, 2017, with limited exceptions, Otter Tail Corporation is no longer subject to examinations by taxing authorities for tax years prior to 2014 for federal and North Dakota state income taxes and for years prior to 2013 for Minnesota state income taxes.

TCJA

In December 2017 the TCJA was enacted. The TCJA includes a number of changes to existing U.S. tax laws that impact OTP, most notably a reduction of the federal corporate income tax rate from 35% to 21% for tax years beginning after December 31, 2017.

OTP measures deferred tax assets and liabilities using enacted tax rates that will apply in the years in which the temporary differences are expected to be recovered or paid. Accordingly, OTP's deferred tax assets and liabilities were remeasured to reflect the reduction in the U.S. corporate income tax rate from 35% to 21%. The revaluation for OTP required the creation of a regulatory liability and an offsetting reduction in deferred tax liability. This regulatory liability will generally be amortized over the remaining life of the related assets. The revaluation resulted in a one-time, non-cash, income tax expense of approximately \$0.5 million in 2017. The impacts of the TCJA adjustments to deferred taxes and regulatory liabilities are provided in the reconciliation below:

<i>(in thousands)</i>	Deferred Tax Liability	Deferred Tax Regulatory Liability
Balance on January 1, 2017	\$ 233,894	\$ 818
Change due to 2017 Accruals and Amortizations	15,930	376
TCJA Deferred Tax Valuation Adjustment	(109,072)	109,072
Tax Effect on TCJA Deferred Tax Valuation Adjustment	(38,786)	38,786
TCJA Adjustment to Income Tax Expense	458	--
Balance on December 31, 2017	\$ 102,424	\$ 149,052

OTP recognized the income tax effects of the TCJA in its 2017 financial statements in accordance with Staff Accounting Bulletin No. 118, which provides SEC staff guidance for the application of ASC Topic 740, Income Taxes, in the reporting period in which the TCJA was signed into law. Current estimates may be revised and are subject to change due, in part, to complexities and uncertainties associated with the TCJA. While OTP is able to make reasonable estimates of the impact of the TCJA for the reduction in the federal corporate tax rate, consequences on OTP's regulatory liabilities and, the final impact of the TCJA may differ from these estimates due to, among other things, changes in OTP's interpretations and assumptions and additional guidance that may be issued by the U.S. Internal Revenue Service, rate regulators or the FASB.

12. Asset Retirement Obligations (AROs)

OTP's AROs are related to its coal-fired generation plants and its 92 wind turbines located in North Dakota. The AROs include items such as site restoration, closure of ash pits, and removal of certain structures, generators, asbestos and storage tanks. OTP has legal obligations associated with the retirement of a variety of other long-lived tangible assets used in electric operations where the estimated settlement costs are individually and collectively immaterial. OTP has no assets legally restricted for the settlement of any of its AROs.

OTP recorded no new AROs in 2017.

Reconciliations of carrying amounts of the present value of OTP's legal AROs, capitalized asset retirement costs and related accumulated depreciation and a summary of settlement activity for the years ended December 31, 2017 and 2016 are presented in the following table:

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Power Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2017	2017/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

<i>(in thousands)</i>	2017	2016
<u>Asset Retirement Obligations</u>		
Beginning Balance	\$ 8,341	\$ 8,084
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	(103)
Accrued Accretion	378	360
Settlements	--	--
Ending Balance	\$ 8,719	\$ 8,341
<u>Asset Retirement Costs Capitalized</u>		
Beginning Balance	\$ 2,983	\$ 3,086
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	(103)
Settlements	--	--
Ending Balance	\$ 2,983	\$ 2,983
<u>Accumulated Depreciation - Asset Retirement Costs Capitalized</u>		
Beginning Balance	\$ 795	\$ 673
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	--
Depreciation Expense	120	122
Settlements	--	--
Ending Balance	\$ 915	\$ 795
<u>Settlements</u>		
	None	None
Original Capitalized Asset Retirement Cost - Retired	\$ --	\$ --
Accumulated Depreciation	--	--
Asset Retirement Obligation	\$ --	\$ --
Settlement Cost	--	--
Gain on Settlement – Deferred Under Regulatory Accounting	\$ --	\$ --

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

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				(1,676,110)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				172,056
3	Preceding Quarter/Year to Date Changes in Fair Value				(137,845)
4	Total (lines 2 and 3)				34,211
5	Balance of Account 219 at End of Preceding Quarter/Year				(1,641,899)
6	Balance of Account 219 at Beginning of Current Year				(1,641,899)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				168,199
8	Current Quarter/Year to Date Changes in Fair Value				(487,881)
9	Total (lines 7 and 8)				(319,682)
10	Balance of Account 219 at End of Current Quarter/Year				(1,961,581)

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			(1,676,110)		
2			172,056		
3			(137,845)		
4			34,211	49,828,835	49,863,046
5			(1,641,899)		
6			(1,641,899)		
7			168,199		
8			(487,881)		
9			(319,682)	49,446,542	49,126,860
10			(1,961,581)		

**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)	1,680,183,079	1,680,183,079
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	299,158,257	299,158,257
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	1,979,341,336	1,979,341,336
9	Leased to Others		
10	Held for Future Use	29,656	29,656
11	Construction Work in Progress	132,556,715	132,556,715
12	Acquisition Adjustments	1,647,128	1,647,128
13	Total Utility Plant (8 thru 12)	2,113,574,835	2,113,574,835
14	Accum Prov for Depr, Amort, & Depl	745,531,210	745,531,210
15	Net Utility Plant (13 less 14)	1,368,043,625	1,368,043,625
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	737,319,904	737,319,904
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	6,564,178	6,564,178
22	Total In Service (18 thru 21)	743,884,082	743,884,082
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	1,647,128	1,647,128
33	Total Accum Prov (equals 14) (22,26,30,31,32)	745,531,210	745,531,210

Name of Respondent
Otter Tail Power Company

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

Date of Report
(Mo, Da, Yr)
12/31/2017

Year/Period of Report
End of 2017/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
					3
					4
					5
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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) 12/31/2017	Year/Period of Report 2017/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

Schedule Page: 200 Line No.: 8 Column: c

Per its FERC-approved tariff, the Company uses a 13-month average of gross electric plant in service for rate-making purposes, illustrated as follows for the current year:

	Gross Electric Plant In Service
December 31, 2016	1,858,680,196
January 31, 2017	1,858,800,896
February 28, 2017	1,860,017,712
March 31, 2017	1,867,011,607
April 30, 2017	1,867,472,441
May 31, 2017	1,868,733,275
June 30, 2017	1,869,251,346
July 31, 2017	1,878,308,845
August 31, 2017	1,880,586,162
September 30, 2017	1,951,698,031
October 31, 2017	1,957,101,959
November 30, 2017	1,966,836,109
December 31, 2017	1,979,341,336
13-month average for rate-making	1,897,218,455

Schedule Page: 200 Line No.: 11 Column: c

Per its FERC-approved tariff, the Company uses a 13-month average of electric transmission plant in service for rate-making purposes, illustrated as follows for the current year:

	Account 107 Balance	CWIP Not in Rates	CWIP in Rate Base
December 31, 2016	149,997,025	40,502,059	109,494,966
January 31, 2017	156,650,635	43,511,212	113,139,423
February 28, 2017	161,946,994	46,085,191	115,861,803
March 31, 2017	161,299,616	42,176,386	119,123,230
April 30, 2017	165,195,028	44,857,758	120,338,270
May 31, 2017	173,377,649	47,699,106	125,678,543
June 30, 2017	182,389,084	53,352,759	129,036,325
July 31, 2017	184,392,429	49,860,915	134,531,514
August 31, 2017	192,589,967	52,204,354	140,385,613
September 30, 2017	130,795,417	55,440,860	75,354,557
October 31, 2017	135,051,333	55,479,466	79,571,867
November 30, 2017	135,397,660	51,099,439	84,298,221
December 31, 2017	132,556,715	45,747,372	86,809,343
13-month average for rate-making			110,278,744

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		
3	Nuclear Materials		
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)		
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)		
10	SUBTOTAL (Total 8 & 9)		
11	Spent Nuclear Fuel (120.4)		
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)		
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)		
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

Name of Respondent Otter Tail Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report End of <u>2017/Q4</u>
NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)			

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Changes during Year		Balance End of Year (f)	Line No.
Amortization (d)	Other Reductions (Explain in a footnote) (e)		
			1
			2
			3
			4
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			22

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 202 Line No.: 2 Column: b
Not applicable

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	1,301,974	
4	(303) Miscellaneous Intangible Plant	7,207,561	2,698,183
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	8,509,535	2,698,183
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,654,157	
9	(311) Structures and Improvements	125,448,487	338,293
10	(312) Boiler Plant Equipment	332,078,542	6,333,691
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	65,898,798	290,406
13	(315) Accessory Electric Equipment	36,676,241	53,629
14	(316) Misc. Power Plant Equipment	6,434,344	238,978
15	(317) Asset Retirement Costs for Steam Production	2,758,152	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	570,948,721	7,254,997
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	299,623	
28	(331) Structures and Improvements	351,711	
29	(332) Reservoirs, Dams, and Waterways	4,277,057	
30	(333) Water Wheels, Turbines, and Generators	1,373,864	
31	(334) Accessory Electric Equipment	592,400	6,783
32	(335) Misc. Power PLant Equipment	442,624	
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)	7,337,279	6,783
36	D. Other Production Plant		
37	(340) Land and Land Rights	126,762	
38	(341) Structures and Improvements	12,946,210	
39	(342) Fuel Holders, Products, and Accessories	1,748,265	
40	(343) Prime Movers	32,326,158	14,780
41	(344) Generators	241,601,356	460,877
42	(345) Accessory Electric Equipment	20,551,752	134,375
43	(346) Misc. Power Plant Equipment	628,271	
44	(347) Asset Retirement Costs for Other Production	224,652	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	310,153,426	610,032
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	888,439,426	7,871,812

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	14,433,626	-16,668
49	(352) Structures and Improvements		
50	(353) Station Equipment	95,137,119	27,783,944
51	(354) Towers and Fixtures	81,106,418	1,131,746
52	(355) Poles and Fixtures	112,685,715	30,631,296
53	(356) Overhead Conductors and Devices	107,171,849	32,120,370
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices	77,461	
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	410,612,188	91,650,688
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	1,306,581	
61	(361) Structures and Improvements		
62	(362) Station Equipment	78,123,698	3,216,831
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	70,849,812	2,475,570
65	(365) Overhead Conductors and Devices	49,842,694	2,293,211
66	(366) Underground Conduit		
67	(367) Underground Conductors and Devices	74,699,090	2,990,629
68	(368) Line Transformers	93,713,428	4,855,223
69	(369) Services	53,979,165	1,517,939
70	(370) Meters	33,498,134	1,368,316
71	(371) Installations on Customer Premises	4,786,866	395,823
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	5,464,003	319,070
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	466,263,471	19,432,612
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	1,521,896	
87	(390) Structures and Improvements	30,574,256	913,428
88	(391) Office Furniture and Equipment	5,894,128	1,650,788
89	(392) Transportation Equipment	32,976,572	3,482,003
90	(393) Stores Equipment		
91	(394) Tools, Shop and Garage Equipment	4,614,483	213,938
92	(395) Laboratory Equipment		
93	(396) Power Operated Equipment	616,047	33,469
94	(397) Communication Equipment	8,658,194	2,173,881
95	(398) Miscellaneous Equipment		
96	SUBTOTAL (Enter Total of lines 86 thru 95)	84,855,576	8,467,507
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	84,855,576	8,467,507
100	TOTAL (Accounts 101 and 106)	1,858,680,196	130,120,802
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	1,858,680,196	130,120,802

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
			14,416,958	48
				49
1,239,556		-1,594	121,679,913	50
		25,830,245	108,068,409	51
423,670		-25,827,042	117,066,299	52
314,666		-1,609	138,975,944	53
				54
			77,461	55
				56
				57
1,977,892			500,284,984	58
				59
			1,306,581	60
				61
756,709		-2,579	80,581,241	62
				63
127,046			73,198,336	64
222,456			51,913,449	65
				66
296,444			77,393,275	67
594,326		2,579	97,976,904	68
51,715			55,445,389	69
543,692			34,322,758	70
172,355			5,010,334	71
				72
85,462			5,697,611	73
				74
2,850,205			482,845,878	75
				76
				77
				78
				79
				80
				81
				82
				83
				84
				85
			1,521,896	86
345,993			31,141,691	87
1,170,492			6,374,424	88
1,412,753			35,045,822	89
				90
			4,828,421	91
				92
28,186			621,330	93
204,662			10,627,413	94
				95
3,162,086			90,160,997	96
				97
				98
3,162,086			90,160,997	99
9,459,662			1,979,341,336	100
				101
				102
				103
9,459,662			1,979,341,336	104

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Power Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2017	2017/Q4
FOOTNOTE DATA			

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

Per its FERC-approved tariff, the Company uses a 13-month average of intangible electric plant in service for rate-making purposes, illustrated as follows for the current year:

	Intangible Electric Plant In Service
December 31, 2016	8,509,535
January 31, 2017	8,509,535
February 28, 2017	8,933,822
March 31, 2017	8,930,933
April 30, 2017	8,930,933
May 31, 2017	9,048,445
June 30, 2017	9,046,355
July 31, 2017	9,046,355
August 31, 2017	9,046,355
September 30, 2017	9,046,355
October 31, 2017	9,850,040
November 30, 2017	10,762,499
December 31, 2017	11,207,718
13-month average for rate-making	9,297,606

Schedule Page: 204 Line No.: 46 Column: g

Per its FERC-approved tariff, the Company uses a 13-month average of production plant in service for rate-making purposes, illustrated as follows for the current year:

	Production Plant In Service
December 31, 2016	888,439,426
January 31, 2017	888,467,610
February 28, 2017	888,491,545
March 31, 2017	888,482,368
April 30, 2017	888,482,368
May 31, 2017	888,343,500
June 30, 2017	888,372,464
July 31, 2017	892,059,755
August 31, 2017	892,100,965
September 30, 2017	892,131,742
October 31, 2017	892,425,417
November 30, 2017	893,296,808
December 31, 2017	894,841,759
13-month average for rate-making	890,456,594

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

Per its FERC-approved tariff, the Company uses a 13-month average of electric transmission plant in service for

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) 12/31/2017	Year/Period of Report 2017/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

rate-making purposes, illustrated as follows for the current year:

Electric Transmission Plant In Service		
December 31, 2016	410,612,188	
January 31, 2017	410,730,360	
February 28, 2017	410,731,974	
March 31, 2017	414,118,137	
April 30, 2017	414,507,175	
May 31, 2017	414,745,462	
June 30, 2017	414,000,054	
July 31, 2017	418,867,281	
August 31, 2017	419,503,876	
September 30, 2017	489,553,536	
October 31, 2017	491,580,012	
November 30, 2017	498,224,655	
December 31, 2017	500,284,984	
13-month average for rate-making		439,035,361

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

Per its FERC-approved tariff, the Company uses a 13-month average of distribution plant in service for rate-making purposes, illustrated as follows for the current year:

Distribution Plant In Service		
December 31, 2016	466,263,471	
January 31, 2017	466,291,619	
February 28, 2017	467,579,958	
March 31, 2017	471,432,989	
April 30, 2017	471,678,478	
May 31, 2017	471,939,332	
June 30, 2017	473,295,024	
July 31, 2017	473,819,978	
August 31, 2017	474,971,861	
September 30, 2017	475,992,308	
October 31, 2017	478,086,685	
November 30, 2017	479,090,217	
December 31, 2017	482,845,878	
13-month average for rate-making		473,329,831

Schedule Page: 204 Line No.: 99 Column: g

Per its FERC-approved tariff, the Company uses a 13-month average of general plant in service for rate-making purposes, illustrated as follows for the current year:

General Plant

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) 12/31/2017	Year/Period of Report 2017/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

	In Service
December 31, 2016	84,855,576
January 31, 2017	84,801,772
February 28, 2017	84,280,414
March 31, 2017	84,047,181
April 30, 2017	83,873,488
May 31, 2017	84,656,537
June 30, 2017	84,537,450
July 31, 2017	84,515,477
August 31, 2017	84,963,105
September 30, 2017	84,974,091
October 31, 2017	85,159,805
November 30, 2017	85,461,930
December 31, 2017	90,160,997
13-month average for rate-making	85,099,063

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	Not applicable.				
2					
3					
4					
5					
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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	Various			29,656
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Various			
23				
24				
25				
26				
27				
28				
29				
30				
31				
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33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			29,656

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) 12/31/2017	Year/Period of Report 2017/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

Schedule Page: 214 Line No.: 2 Column: d

Per its FERC-approved tariff, the Company uses a 13-month average of electric plant held for future use for rate-making purposes, illustrated as follows for the current year:

	Transmission	Distribution	Total
December 31, 2016	9,037	20,619	29,656
January 31, 2017	9,037	20,619	29,656
February 28, 2017	9,037	20,619	29,656
March 31, 2017	9,037	20,619	29,656
April 30, 2017	9,037	20,619	29,656
May 31, 2017	9,037	20,619	29,656
June 30, 2017	9,037	20,619	29,656
July 31, 2017	9,037	20,619	29,656
August 31, 2017	9,037	20,619	29,656
September 30, 2017	9,037	20,619	29,656
October 31, 2017	9,037	20,619	29,656
November 30, 2017	9,037	20,619	29,656
December 31, 2017	9,037	20,619	29,656
13-month average for rate-making			29,656

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	Big Stone, SD - Ellendale Sub, ND - Construct Transmission Facilities	895,212
2	System Wide - New Natural Gas Generation - Construct Generating Plant	3,833,703
3	Big Stone, SD - Ellendale, ND CMA - Construct Transmission Facilities	78,414,130
4	Big Stone, SD - Ellendale, ND RETENTION - Construct Transmission Facilities	3,170,514
5	System Wide - CISone - Purchase Intangible Plant	11,446,139
6	System Wide - Energy Management System Upgrade - Purchase Intangible Plant	951,146
7	Big Stone, SD - Bottom Ash and Economizer Ash Equipment - Construct Generating Plant	1,159,264
8	Merricourt, ND - Wind Project - Construct Generating Plant	4,469,508
9	Total Projects under \$1,000,000	28,217,099
10		
11		
12		
13		
14		
15		
16		
17		
18		
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33		
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37		
38		
39		
40		
41		
42		
43	TOTAL	132,556,715

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	696,458,493	696,458,493		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	49,827,070	49,827,070		
4	(403.1) Depreciation Expense for Asset Retirement Costs	119,876	119,876		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,845,271	1,845,271		
7	Other Clearing Accounts	-79,146	-79,146		
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	51,713,071	51,713,071		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	9,459,660	9,459,660		
13	Cost of Removal	2,693,917	2,693,917		
14	Salvage (Credit)	2,296,657	2,296,657		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	9,856,920	9,856,920		
16	Other Debit or Cr. Items (Describe, details in footnote):	-994,740	-994,740		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	737,319,904	737,319,904		

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

20	Steam Production	247,752,679	247,752,679		
21	Nuclear Production				
22	Hydraulic Production-Conventional	4,739,038	4,739,038		
23	Hydraulic Production-Pumped Storage				
24	Other Production	115,126,944	115,126,944		
25	Transmission	120,734,336	120,734,336		
26	Distribution	210,361,952	210,361,952		
27	Regional Transmission and Market Operation				
28	General	38,604,955	38,604,955		
29	TOTAL (Enter Total of lines 20 thru 28)	737,319,904	737,319,904		

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 219 Line No.: 7 Column: c

Inventory costs cleared to construction or utility operating expense.

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

The net activity during the year for construction/removal not classified.

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

Per its FERC-approved tariff, the Company uses a 13-month average of accumulated depreciation for rate-making purposes, illustrated as follows for the current year:

	Production *	Transmission	Distribution	General	Total
December 31, 2016	340,699,445	115,585,011	203,012,975	37,161,061	696,458,493
January 31, 2017	343,041,908	116,113,770	203,617,880	37,156,576	699,930,134
February 28, 2017	345,414,827	116,727,220	204,138,139	36,993,260	703,273,446
March 31, 2017	347,610,477	117,213,778	204,838,092	37,045,493	706,707,840
April 30, 2017	349,982,629	117,689,290	205,252,421	37,223,774	710,148,115
May 31, 2017	351,853,493	118,413,710	205,594,371	37,472,270	713,333,844
June 30, 2017	354,111,082	117,923,290	206,215,755	37,693,264	715,943,390
July 31, 2017	356,426,393	118,632,641	207,049,785	37,841,436	719,950,255
August 31, 2017	358,727,093	118,503,029	207,737,874	37,692,435	722,660,430
September 30, 2017	361,112,118	118,916,030	208,245,356	37,919,420	726,192,923
October 31, 2017	362,999,471	119,454,587	208,989,033	38,109,734	729,552,825
November 30, 2017	365,349,043	120,106,326	209,809,728	38,362,209	733,627,306
December 31, 2017	367,618,662	120,734,336	210,361,952	38,604,955	737,319,904
13-month average for rate-making	354,226,665	118,154,848	206,527,951	37,636,607	716,546,070

* Production is a total of lines 20 through 24 on page 219.

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	Not applicable			
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	Total Cost of Account 123.1 \$	0	TOTAL	

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
				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
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				31
				32
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				35
				36
				37
				38
				39
				40
				41
				42

Name of Respondent Otter Tail Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report End of <u>2017/Q4</u>
------------------------------------------------	-----------------------------------------------------------------------------------------------------------------------	----------------------------------------------	------------------------------------------------

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)	9,830,796	8,894,145	Production
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)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	6,454,839	6,672,371	Production
8	Transmission Plant (Estimated)	5,284,837	5,175,554	Various
9	Distribution Plant (Estimated)	6,764,528	7,126,388	Various
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	318,305	269,875	Fleet Service
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	18,822,509	19,244,188	
13	Merchandise (Account 155)			
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				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	28,653,305	28,138,333	

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) 12/31/2017	Year/Period of Report 2017/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

Schedule Page: 227 Line No.: 7 Column: c

Per its FERC-approved tariff, the Company uses a 13-month average of materials and supplies for rate-making purposes, illustrated as follows for the current year:

	Production Plant
December 31, 2016	6,454,839
January 31, 2017	6,544,092
February 28, 2017	6,528,284
March 31, 2017	6,575,304
April 30, 2017	6,699,188
May 31, 2017	6,662,812
June 30, 2017	6,684,023
July 31, 2017	6,706,389
August 31, 2017	6,653,889
September 30, 2017	6,652,335
October 31, 2017	6,582,870
November 30, 2017	6,723,131
December 31, 2017	6,672,371
13-month average for rate-making	6,626,117

Schedule Page: 227 Line No.: 8 Column: c

Per its FERC-approved tariff, the Company uses a 13-month average of materials and supplies for rate-making purposes, illustrated as follows for the current year:

	Transmission Plant
December 31, 2016	5,284,837
January 31, 2017	5,241,833
February 28, 2017	5,243,924
March 31, 2017	5,297,203
April 30, 2017	5,261,490
May 31, 2017	5,313,197
June 30, 2017	5,298,053
July 31, 2017	5,256,496
August 31, 2017	5,298,260
September 30, 2017	5,403,703
October 31, 2017	5,458,899
November 30, 2017	5,365,707
December 31, 2017	5,175,554
13-month average for rate-making	5,299,935

Schedule Page: 227 Line No.: 9 Column: c

Per its FERC-approved tariff, the Company uses a 13-month average of materials and supplies for rate-making purposes, illustrated as follows for the current year:

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) 12/31/2017	Year/Period of Report 2017/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

	Distribution Plant
December 31, 2016	6,764,528
January 31, 2017	6,848,833
February 28, 2017	7,148,916
March 31, 2017	7,902,244
April 30, 2017	8,002,377
May 31, 2017	7,905,591
June 30, 2017	7,788,108
July 31, 2017	7,477,464
August 31, 2017	7,516,082
September 30, 2017	7,329,271
October 31, 2017	7,372,348
November 30, 2017	7,373,455
December 31, 2017	7,126,388
13-month average for rate-making	7,427,354

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

Consists of parts inventory at the Fleet Service Department.

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

Per its FERC-approved tariff, the Company uses a 13-month average of materials and supplies for rate-making purposes, illustrated as follows for the current year:

	Assigned to - Other
December 31, 2016	318,305
January 31, 2017	304,477
February 28, 2017	287,549
March 31, 2017	288,206
April 30, 2017	272,416
May 31, 2017	276,011
June 30, 2017	264,916
July 31, 2017	269,636
August 31, 2017	283,002
September 30, 2017	291,679
October 31, 2017	282,536
November 30, 2017	270,695
December 31, 2017	269,875
13-month average for rate-making	283,023

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		2018	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	53,759.00	31,385	15,310.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA	26.00			
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	7,081.00	15,509		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	46,704.00	15,876	15,310.00	
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	202.96		202.96	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	202.96			
40	Balance-End of Year			202.96	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	202.96	13		
45	Gains	202.96	13		
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.

2019		2020		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
14,054.00		14,054.00		365,404.00		462,581.00	31,385	1
								2
								3
				14,054.00		14,054.00		4
						26.00		5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						7,081.00	15,509	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
14,054.00		14,054.00		379,458.00		469,580.00	15,876	29
								30
								31
								32
								33
								34
								35
202.96		202.96		9,945.16		10,757.00		36
				405.93		405.93		37
								38
				202.96		405.92		39
202.96		202.96		10,148.13		10,757.01		40
								41
								42
								43
				202.96	3	405.92		16 44
				202.96	3	405.92		16 45
								46

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 228 Line No.: 1 Column: b

Includes 1,256 of initial allocations from EPA and 958 of rollover allowances for Cross State Air Pollution Rule.

Schedule Page: 228 Line No.: 1 Column: d

Includes 1,256 of initial allocations from EPA for Cross State Air Pollution Rule.

Schedule Page: 228 Line No.: 18 Column: b

Includes 940 of emission charges for Cross State Air Pollution Rule.

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		2018	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	1,863.00		876.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA	18.00			
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	409.00			
19	Other:				
20	EPA Adjustment				
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	1,472.00		876.00	
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/transferees 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.

2019		2020		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
						2,739.00		1
								2
								3
								4
						18.00		5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						409.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
						2,348.00		29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 229 Line No.: 1 Column: b

Includes 876 of initial allocations from EPA and 987 rollover allowances for Cross State Air Pollution Rule.

Schedule Page: 229 Line No.: 1 Column: d

Includes 876 of initial allocations from EPA for Cross State Air Pollution Rule.

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	Not applicable.					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent
Otter Tail Power Company

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

Date of Report
(Mo, Da, Yr)
12/31/2017

Year/Period of Report
End of 2017/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21	BSII cancelled project - MN	-46,926		See note	46,926	
22	- Generation					
23	MPUC order issued 04-25-2011.					
24	Remaining recovery period: 10 mos					
25						
26	BSII cancelled project - MN	2,912,106		See note	-526,510	2,285,597
27	-Transmission					
28	MPUC order issued 04-25-2011.					
29	Remaining recovery period: 52 mos					
30						
31	BSII cancelled project - SD	409,690		407	-100,331	309,356
32	-Generation					
33	SDPUC order issued 02-11-2010					
34	Remaining recovery period: 25 mos					
35						
36	BSII cancelled project - SD	232,957				232,957
37	-Transmission					
38	SDPUC order issued 04-30-2013					
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	3,507,827			-579,915	2,827,910

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 230 Line No.: 21 Column: d
Accounts 407 and 431 were used.

Schedule Page: 230 Line No.: 26 Column: d
Accounts 407 and 419 were used.

Schedule Page: 230 Line No.: 36 Column: b
This is the South Dakota transmission balance that will be deferred until the next rate case.

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	Transmission Studies				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	Generation Studies				
22	BSB Facility Study	1,849	456	2,151	456
23	J493 Facility Study	43,454	456	51,207	456
24	Oakes Facility Study	1,193	456	1,398	456
25	R101 Facility Study	379	456	436	456
26	J436 Facility Study	34,025	456	32,259	456
27	R101 Fast Track Studies	997	456	952	456
28	J488/J489 Dakota Range III and IV	411	456		456
29	Interconnection Facility Study				
30	J526 Interconnection Facility Study	548	456		456
31	J459/J613/J637/J638 Short	625	456		456
32	Circuit Studies				
33					
34					
35					
36					
37					
38					
39					
40					

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	Deferred Income Tax Adjustments					
2	Due to ASC 740 on:					
3	Property/Non Property Related Items	1,013,976	692,121	282	1,706,097	
4						
5	Asset Retirement Obligation Capitalized					
6	Hoot Lake Plant	2,034,728	107,008			2,141,736
7	Big Stone Plant	600,113	91,976			692,089
8	Coyote Station	2,379,705	215,931			2,595,636
9	Wind Generation - Langdon	461,792	28,081	407.4	2,332	487,541
10	Wind Generation - Ashtabula	346,583	29,366	407.4	1,980	373,969
11	Wind Generation - Luverne	330,013	30,229			360,242
12						
13	Derivatives-Marked to Market Losses	10,530,483		253	4,062,921	6,467,562
14						
15	MISO Schedules 26 & 26A Accrual	214,159	699,820	See Note	857,250	56,729
16						
17	MN Renewable Resource Rider	34,181		407.3	34,181	
18	ND Renewable Resource Rider	1,801,119	1,474,564	See Note	2,833,892	441,791
19						
20	ESSRP	2,948,350	622,273	228.3	301,320	3,269,303
21						
22	Pension	98,179,649	6,410,885	228.3	5,209,774	99,380,760
23						
24	MN Transmission Revenue Rider		1,038,930			1,038,930
25	ND Transmission Revenue Rider	568,166	717,583	See Note	568,166	717,583
26	SD Transmission Revenue Rider	332,917	172,235	See Note	332,917	172,235
27						
28	Post Retirement Medical Benefits	13,582,179	6,280,624	228.3	935,827	18,926,976
29						
30	Conservation Improvement Program - MN	9,887,854	7,947,146	186	7,835,125	9,999,875
31	Energy Efficiency Program - SD	105,900	380,199	186	327,115	158,984
32						
33	MN Rate Case Expense Deferral	1,081,589	144,931	407.4	959,501	267,019
34	ND Rate Case Expense Deferral		309,293			309,293
35						
36	ND Environmental Cost Recovery Rider	112,527	244,335	See Note	205,139	151,723
37						
38	MN EITE Cost Recovery Rider		75,291			75,291
39						
40						
41						
42	See footnote 3 in Notes to Financial Statements					
43	for amortization periods.					
44	TOTAL	146,545,983	27,712,821		26,173,537	148,085,267

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 232 Line No.: 15 Column: d

Accounts 440, 442, 444, and 445 were debited.

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

Accounts 440, 442, 444, and 445 were debited.

Schedule Page: 232 Line No.: 25 Column: d

Accounts 440, 442, 444, and 445 were debited.

Schedule Page: 232 Line No.: 26 Column: d

Accounts 440, 442, 444, and 445 were debited.

Schedule Page: 232 Line No.: 36 Column: d

Accounts 440, 442, 444, and 445 were debited.

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	Conservation Improvement					
2	Programs - MN		7,360,726	182.3	7,360,726	
3						
4	Energy Efficiency Program - SD		24,284	182.3	24,284	
5						
6	Renewable Energy Certificates		60,876			60,876
7						
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11						
12						
13						
14						
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44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL					60,876

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	Property Insurance Reserve		
3	Workman's Compensation Reserve	303,140	309,086
4	Medical Insurance Reserve		
5	Injuries and Damages Reserve		
6	See Note Below	127,218,951	103,382,911
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	127,522,091	103,691,997
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	127,522,091	103,691,997

Notes

	Balance at Beginning of Year	Balance at End of Year
	-----	-----
Post Retirement Medical Benefits	21,385,284	22,151,116
Executive Supplemental Pension	4,436,130	4,546,574
Reserve for Bad Debts	339,929	447,792
Accrued Vacation Pay	1,726,790	1,716,537
Capitalized Int. on Construction	5,609,720	5,881,714
Post Employment Medical Benefits	457,711	371,238
Incentive Plans	566,197	886,324
Nonqualified Retirement Savings	311,250	388,172
Federal NOL Carryforward	6,496,988	1,408,821
Reserve for Loan Pools	4,683	4,683
Property Damage Reserves	(304,432)	(304,344)
Capitalized A & G	2,541,368	2,230,088
Customer Rebates Capitalized	120,832	125,038
Stock Incentives	11,197	(47,662)
CIAC Capitalized	101,838	79,205
BSII Discount	213,216	166,821
Unicap Adjustment	35,983	36,479
Medicare Part D	465,274	446,868
Research Credit Carryforward	374,580	374,580
Flow-Through Items	113,284	79,072
State NOL Carryforward	2,538,110	2,301,359
Wind Energy Income Tax Credits-ND	40,868,577	35,794,016
ASC 740 Unamortized ITC	817,529	514,871
SFAS 109 Recognition of Regulatory Assets (Liab.)	4,874,172	1,899,424
Excess Accum Defrd Tax due to Federal Rate Change	0	(18,755,431)
ASC 740 Recognition of Regulatory Assets (Liab.)	4,874,172	(16,856,007)
Wind Production Tax Credit Deferral (Asset)	33,112,740	40,639,556
	-----	-----
	127,218,951	103,382,913

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	Account 201 (Par)			
2	Common Stock	50,000,000	5.00	
3				
4				
5	TOTAL COMMON	50,000,000		
6				
7	Cumulative Preferred	1,500,000		
8	Cumulative Preference	1,000,000		
9	TOTAL PREFERRED	2,500,000		
10				
11				
12				
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14				
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Name of Respondent
Otter Tail Power Company

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

Date of Report
(Mo, Da, Yr)
12/31/2017

Year/Period of Report
End of 2017/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
Shares (e)	Amount (f)	AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
		Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
100	500					2
						3
						4
100	500					5
						6
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OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

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

- (a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
- (b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
- (c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
- (d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Parent company investment in Otter Tail Power Company	339,988,966
2	Additional parent investment	37,000,000
3		
4		
5		
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40	TOTAL	376,988,966

Name of Respondent Otter Tail Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report End of <u>2017/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	Common Shares	
2		
3	Not applicable	
4		
5		
6		
7		
8		
9		
10		
11		
12		
13	Cumulative Preferred Shares	
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 - Bonds		
2	2021 Series 4.63% Notes	140,000,000	891,854
3			
4	Senior Unsecured Notes 6.47%, Series D	50,000,000	665,975
5			
6	Senior Unsecured Notes 6.37%, Series C	42,000,000	540,768
7			
8	Senior Unsecured Notes 6.15%, Series B	30,000,000	386,988
9			
10	Senior Unsecured Notes 4.68%, Series A	60,000,000	195,814
11			
12	Senior Unsecured Notes 5.47%, Series B	90,000,000	294,168
13			
14	Senior Unsecured Notes 5.95%, Series A		
15			
16			
17			
18			
19			
20			
21			
22	Account 222 - Reacquired Bonds - None		
23	Account 223 - Advances from associated companies - None		
24	Account 224 Other Long Term Debt - None		
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	412,000,000	2,975,567

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
07/29/2011	12/01/2021	12/01/2011	11/30/2021	140,000,000	6,482,000	2
						3
08/20/2007	8/20/2037	8/20/2007	8/20/2037	50,000,000	3,235,000	4
&10/1/2007						5
08/20/2007	08/20/2027	8/20/2007	8/20/2027	42,000,000	2,675,400	6
&10/1/2007						7
10/01/2007	08/20/2022	10/01/2007	08/20/2022	30,000,000	1,845,000	8
						9
02/27/2014	02/27/2029	02/27/2014	02/27/2029	60,000,000	2,808,000	10
						11
02/27/2014	02/27/2044	02/27/2014	02/27/2044	90,000,000	4,923,000	12
						13
10/01/2007	08/20/2017	10/01/2007	08/20/2017		1,254,458	14
						15
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						32
				412,000,000	23,222,858	33

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 256 Line No.: 14 Column: a

Bond series was retired in August 2017.

Schedule Page: 256 Line No.: 16 Column: a

Instruction 9 - Unamortized debt expense remaining on bonds retired early is transferred to Account 189 and amortized over remaining life of the bonds.

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)	49,446,542
2		
3		
4	Taxable Income Not Reported on Books	
5	Interest capitalized on construction	1,251,731
6	Net gain from property retirements	1,112,742
7	Miscellaneous taxable items	6,000
8	Conservation improvement program	-2,752,813
9	Deductions Recorded on Books Not Deducted for Return	
10	Add back federal income taxes (includes deferreds & ITC adjustment)	17,012,486
11	Provision for reserves	8,726,398
12	Miscellaneous unallowed deductions	59,595,185
13		
14	Income Recorded on Books Not Included in Return	
15	Tax exempt interest	
16	Equity in earnings of subsidiaries	
17	Wind rider revenue	7,389,492
18	Miscellaneous income not taxable	
19	Deductions on Return Not Charged Against Book Income	
20	Excess tax depreciation over book depreciation	34,438,568
21	Removal costs	3,006,569
22	Charges to reserves	6,708,809
23	Leveraged ESOP deduction	1,557,021
24	Sec 481(a) Cap to Repair basis adjustments	
25	Miscellaneous other deductions	66,202,578
26		
27	Federal Tax Net Income	15,095,234
28	Show Computation of Tax:	
29	Federal tax (Line 27 x 35%)	5,283,332
30	Tax (credits) and adjustments	-6,000
31	Prior period adjustments	166,460
32	Transfer net operating loss to deferred carryforward	-5,277,334
33	Total federal income tax	166,458
34		
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Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Power Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2017	2017/Q4
FOOTNOTE DATA			

Schedule Page: 261 Line No.: 44 Column: a

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

Otter Tail Power Company is a member of an affiliated group which will file a consolidated Federal Income tax return for the year 2017. The other members of the affiliated group and their respective federal income tax provisions are as follows:

1	Otter Tail Corporation	(2,784,274)
2	Varistar Corporation	(83,978)
3	IMD, Inc.	0
4	BTD Manufacturing, Inc.	2,933,494
5	Northern Pipe Products, Inc.	4,075,312
6	Vinyltech Corporation	5,743,490
7	Otter Tail Energy Services Company	0
8	T O. Plastics, Inc.	922,069
9	Shrco, Inc.	(52,243)
10	Otter Tail Assurance Limited	167,112
11	AEV, Inc.	0
12	ASI, Inc.	(18,443)
13	Miller Welding & Iron Works, Inc.	(1,229,969)

	Total	9,672,570

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					
2	Income			5,443,708	5,443,709	
3	Unemployment	568		35,178	35,221	
4	FICA			4,887,718	4,887,718	
5						
6	MINNESOTA					
7	Property	9,700,000		9,590,802	9,392,221	
8	Income	604,014		782,186	2,348,268	
9	Unemployment	1,239		38,570	39,210	
10						
11	NORTH DAKOTA					
12	Property	2,500,000		2,937,917	2,537,915	
13	Income			267,009	267,009	
14	Unemployment	915		38,145	38,098	
15	Coal Conversion	187,424		2,072,885	2,099,595	
16						
17	SOUTH DAKOTA					
18	Property	1,800,000		1,855,252	1,553,833	
19	Unemployment	72		8,424	8,299	
20						
21	OTHER STATES					
22	Income					
23	Railcar	7,128		21,676	19,811	
24						
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40						
41	TOTAL	14,801,360		27,979,470	28,670,907	

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
524		-213,688			5,657,396	2
					35,178	3
					4,887,718	4
						5
						6
9,898,581		9,590,802				7
-962,068		724,787			57,399	8
599					38,570	9
						10
						11
2,900,002		2,873,381			64,536	12
		-18,235			285,244	13
962					38,145	14
160,714		2,072,885				15
						16
						17
2,101,419		1,855,252				18
198					8,424	19
						20
						21
						22
8,993					21,676	23
						24
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14,109,924		16,885,184			11,094,286	41

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

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

Account 409.2: 380,146; Other: 5,277,250

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

Account 184

Schedule Page: 262 Line No.: 4 Column: I

Account 184

Schedule Page: 262 Line No.: 8 Column: I

Account 409.2: 57,399

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

Account 184

Schedule Page: 262 Line No.: 12 Column: I

Account 921: 56,688; Account 408.2: 7,848

Schedule Page: 262 Line No.: 13 Column: I

Account 409.2: 18,238; Other: 267,006

Schedule Page: 262 Line No.: 14 Column: I

Account 184

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

Account 184

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

Account 151

Name of Respondent
Otter Tail Power Company

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

Date of Report
(Mo, Da, Yr)
12/31/2017

Year/Period of Report
End of 2017/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%	22,539,349	190		411.4	1,306,823	
3	4%						
4	7%						
5	10%	309,965	411.4		411.4	163,740	
6							
7							
8	TOTAL	22,849,314				1,470,563	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
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48							

Name of Respondent
Otter Tail Power Company

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

Date of Report
(Mo, Da, Yr)
12/31/2017

Year/Period of Report
End of 2017/Q4

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
21,232,526	25 years		2
			3
			4
146,225	33-1/3 years		5
			6
			7
21,378,751			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
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			39
			40
			41
			42
			43
			44
			45
			46
			47
			48

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	Prepaid Electric Revenue	1,176,332	456	428,403	328,097	1,076,026
2	Payroll Clearing		184	152,357	33,762	-118,595
3	FCA Liability		173	45,107	5,823,543	5,778,436
4	Discontinued Mark-to-Market	6,467,559	182.3	4,062,921		2,404,638
5	Forward Energy Contracts					
6	(Amortization thru Dec 2020)					
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	7,643,891		4,688,788	6,185,402	9,140,505

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	2,645,124	2,242,166	
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	2,645,124	2,242,166	
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)	2,645,124	2,242,166	
18	Classification of TOTAL			
19	Federal Income Tax	2,195,636	1,864,243	
20	State Income Tax	449,488	377,923	
21	Local Income Tax			

NOTES

Name of Respondent

Otter Tail Power Company

This Report Is:

(1) An Original

(2) A Resubmission

Date of Report

(Mo, Da, Yr)

12/31/2017

Year/Period of Report

End of 2017/Q4

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
						4,887,290	4
							5
							6
							7
						4,887,290	8
							9
							10
							11
							12
							13
							14
							15
							16
						4,887,290	17
							18
						4,059,879	19
						827,411	20
							21

NOTES (Continued)

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	337,387,379	25,908,396	13,497,068
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	337,387,379	25,908,396	13,497,068
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	337,387,379	25,908,396	13,497,068
10	Classification of TOTAL			
11	Federal Income Tax	288,392,109	21,107,763	10,783,575
12	State Income Tax	48,995,270	4,800,633	2,713,493
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
62	127,784			See Note	-163,195,990	186,474,995	2
							3
							4
62	127,784				-163,195,990	186,474,995	5
							6
							7
							8
62	127,784				-163,195,990	186,474,995	9
							10
	106,279				-157,989,500	140,620,518	11
62	21,505				-5,206,490	45,854,477	12
							13

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Power Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2017	2017/Q4
FOOTNOTE DATA			

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

Acct 182.3 Adjustment related to ASC 740 and excess accumulated deferred tax due to federal rate change.

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

Amortization of Loss on Reacquired Debt (pre-holdco)	(474,511)
Big Stone II Deferred Costs	(1,105,540)
Retirements Method Change	195,983
South Dakota Flow Thru-Overheads	(10,567)
Prepaid Expenses	(436,310)
ADR Repair Allowance	(2,087,353)
Sec 162 & 174 R&D Deduction	(3,662,397)
Highway Powerline Relocation	(20,854)
AFUDC on Debt	(3,322,741)
Capitalized Overheads	48,639
Repairs Deduction - Basis Adjustments	(13,046,312)
Sec 481(a) Cap to Repair Basis Adjustments (PY)	4,839,651
Legacy Tax Over Book Depreciation	(315,767,476)
North Dakota Investment Tax Credit - Federal Impacts	(6,925,758)
Legacy Accumulated Deferred Tax Due to Federal Rate Change	154,920,724
ASC 740 (SFAS 109) ADIT Credits - Property	379,827

	(186,474,995)
	=====

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	Accum. Deferred Income Tax			
4	Other Utility Operations	17,688,801	13,620,174	8,872,636
5				
6	Accum. Deferred Income Tax			
7	Nonutility & Other	3,695,308		
8				
9	TOTAL Electric (Total of lines 3 thru 8)	21,384,109	13,620,174	8,872,636
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18				
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	21,384,109	13,620,174	8,872,636
20	Classification of TOTAL			
21	Federal Income Tax	16,700,305	10,636,919	6,929,244
22	State Income Tax	4,683,804	2,983,255	1,943,392
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
							3
		See Note	12,459,131			9,977,208	4
							5
							6
1,082,030	935					4,776,403	7
							8
1,082,030	935		12,459,131			14,753,611	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
1,082,030	935		12,459,131			14,753,611	19
							20
845,031	730		12,291,168			8,961,113	21
236,999	205		167,963			5,792,498	22
							23

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Power Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2017	2017/Q4
FOOTNOTE DATA			

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

Adjustment related to ASC 740 and excess accumulated deferred tax due to federal rate change.

Schedule Page: 276 Line No.: 7 Column: a

Deferred taxes related to CIP costs.

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

Pensions	(21,115,708)
Conservation Improvement Program - MN & SD - Net (BTL)	(4,776,403)
Wind Rider Revenue	(246,173)
Transmission Rider Revenue	516,000
Environmental Rider Revenue	671,878
SPP Cost Tracker	239,558
EITE Revenue Tracker	(29,594)
ND Rate Case Expenses	(121,572)
MN Rate Case Expenses	(23,402)
Deferred State NOL's - Fed Haircut	(811,297)
Regulatory Adjustments	850,016
Legacy Accumulated Deferred Tax Due to Federal Rate Change	11,692,288
ASC 740 (SFAS 109) ADIT Credits - Non-Property	(1,599,202)

	(14,753,611)
	=====

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Deferred Income Tax Adjustments Due to					
2	ASC 740	817,529	190	302,658		514,871
3	ADIT Legacy Reclass				148,760,306	148,760,306
4	FAS 109		190	222,668		-222,668
5						
6	Minnesota Portion of Gain on Sale	94,796	407.4	5,576		89,220
7	of Wahpeton Division Office					
8						
9	Reclass SD EEP to Regulatory Liability	15,484		15,484		
10						
11	MN Transmission Revenue Rider	756,734	See note	2,371,246	2,416,066	801,554
12	ND Transmission Revenue Rider	2,163,493	See note	1,914,803	100,325	349,015
13	SD Transmission Revenue Rider		See note	60,358	211,664	151,306
14						
15	MN Future Rate Case Expense Accrual	919,233	407.4	711,673		207,560
16						
17	MN Environmental Revenue Rider	139,028	See note	247,350	1,775,584	1,667,262
18	ND Environmental Revenue Rider		See note	726,454	726,454	
19	SD Environmental Revenue Rider	284,902	See note	180,097	81,857	186,662
20						
21	MN Renewable Resource Rider		See note	163,938	572,932	408,994
22						
23	MISO Schedule 26 and 26A Accrual	131,869			47,670	179,539
24						
25	SPP Cost Recovery Rider Refund			28,587	638,054	609,467
26						
27						
28						
29						
30						
31						
32						
33						
34	See Footnote 3 in Notes to Financial					
35	Statements for amortization periods.					
36						
37						
38						
39						
40						
41	TOTAL	5,323,068		6,950,892	155,330,912	153,703,088

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 278 Line No.: 11 Column: c

Offsetting accounts were 440, 442, 444, and 445.

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

Offsetting accounts were 440, 442, 444, and 445.

Schedule Page: 278 Line No.: 13 Column: c

Offsetting accounts were 440, 442, 444, and 445.

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

Offsetting accounts were 440, 442, 444, and 445.

Schedule Page: 278 Line No.: 18 Column: c

Offsetting accounts were 440, 442, 444, and 445.

Schedule Page: 278 Line No.: 19 Column: c

Offsetting accounts were 440, 442, 444, and 445.

Schedule Page: 278 Line No.: 21 Column: c

Offsetting accounts were 440, 442, 444, and 445.

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	117,437,982	115,782,375
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	139,629,214	136,091,872
5	Large (or Ind.) (See Instr. 4)	113,218,700	116,282,174
6	(444) Public Street and Highway Lighting	3,769,175	3,749,416
7	(445) Other Sales to Public Authorities	3,104,146	3,037,982
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	377,159,217	374,943,819
11	(447) Sales for Resale	5,173,104	4,583,862
12	TOTAL Sales of Electricity	382,332,321	379,527,681
13	(Less) (449.1) Provision for Rate Refunds	4,982,931	3,589,322
14	TOTAL Revenues Net of Prov. for Refunds	377,349,390	375,938,359
15	Other Operating Revenues		
16	(450) Forfeited Discounts	708,000	673,301
17	(451) Miscellaneous Service Revenues	383,969	376,991
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	648,637	531,356
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	7,994,584	6,741,340
22	(456.1) Revenues from Transmission of Electricity of Others	43,474,731	36,517,370
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	53,209,921	44,840,358
27	TOTAL Electric Operating Revenues	430,559,311	420,778,717

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
1,243,194	1,220,946	103,804	103,439	2
				3
1,568,284	1,572,211	26,991	26,849	4
1,938,423	1,893,184	58	56	5
24,995	25,088	404	412	6
40,088	38,993	595	598	7
				8
				9
4,814,984	4,750,422	131,852	131,354	10
225,607	205,208			11
5,040,591	4,955,630	131,852	131,354	12
				13
5,040,591	4,955,630	131,852	131,354	14

Line 12, column (b) includes \$ 2,370,804 of unbilled revenues.

Line 12, column (d) includes 30,684 MWH relating to unbilled revenues

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 300 Line No.: 4 Column: b

Small (or Commercial) includes all customers having a demand of less than 1000 kw.

Schedule Page: 300 Line No.: 5 Column: b

Large (or Industrial) includes all customers having a demand exceeding 1000 kw.

Schedule Page: 300 Line No.: 17 Column: b

Description of Revenue

	<u>Current Year</u>	<u>Prior Year</u>
All others (under \$250,000 each)	\$ 383,969	\$ 376,991
	-----	-----
Total	\$ 383,969	\$ 376,991
	=====	=====

Schedule Page: 300 Line No.: 21 Column: b

Description of Revenue

	<u>Current Year</u>	<u>Prior Year</u>
Sale of steam	\$ 1,724,719	\$ 1,605,959
Integrated transmission deficiency payments	1,419,043	1,700,564
Load control & dispatch	1,505,914	1,561,177
Wind generation development	0	336,154
Sales tax refund on exempt equipment	411,487	0
Capital equipment tax refund	464,863	0
All others (under \$250,000 each)	2,468,458	1,537,486
	-----	-----
Total	\$ 7,994,584	\$ 6,741,340
	=====	=====

Name of Respondent
Otter Tail Power Company

This Report Is:
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Date of Report
(Mo, Da, Yr)
12/31/2017

Year/Period of Report
End of 2017/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Not applicable				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
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27					
28					
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30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

SALES OF ELECTRICITY BY RATE SCHEDULES

- Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
- 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.
- Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
- The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
- For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
- Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential - 440					
2	Residential Service 9.01	862,907	94,170,689	98,388	8,770	0.1091
3						
4	Residential Service (Ctrld Demand					
5	9.02	139,668	11,443,932	6,172	22,629	0.0819
6						
7	Water Heating Ctrld (Off-Peak)					
8	14.01	36,047	2,957,646	15,562	2,316	0.0820
9				-15,562		
10	Controlled Service					
11	14.04,14.05,14.06,14.07	182,639	10,062,967	13,658	13,372	0.0551
12				-13,658		
13	Fixed Time of Delivery Service					
14	14.07	5,736	246,132	436	13,156	0.0429
15				-436		
16	Outdoor lighting-energy only					
17	11.03	78	8,153	16	4,875	0.1045
18				-16		
19	Outdoor Lighting 11.04	3,805	594,814	305	12,475	0.1563
20				-305		
21	Small power producer rider					
22	12.01		608	18		
23				-18		
24	Off-peak Electr Vehicle Rider					
25	14.12	6	423	5	1,200	0.0705
26				-5		
27	Conservation Imp Prog Rev		-1,462,206			
28	Environmental Rider Rev		-337,221			
29	Transmission Cost Recvy		817,520			
30	Renewable Resource Rider		-604,517			
31	Fuel Clause Adjustment Rec		-1,373,654			
32	Southwest Power Pool Rider		-126,559			
33	EITE Revenue Rider		16,406			
34	SUBTOTAL Billed	1,230,886	116,415,133	104,560	11,772	0.0946
35	Unbilled Rev (See Instr. 6)	12,308	1,022,849			0.0831
36	TOTAL - 440	1,243,194	117,437,982	104,560	11,890	0.0945
37						
38	Column D Lines 8,11,14,17,19&22					
39	customers are also served					
40	under other residential service.					
41	TOTAL Billed	4,784,300	369,805,482	135,460	35,319	0.0773
42	Total Unbilled Rev.(See Instr. 6)	30,684	2,370,805	0	0	0.0773
43	TOTAL	4,814,984	372,176,287	135,460	35,545	0.0773

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	Commercial & Industrial-442					
2	General Service					
3	10.01,10.02	753,479	77,050,464	25,015	30,121	0.1023
4						
5	Farm Service					
6	9.03	73,270	6,897,886	2,831	25,881	0.0941
7						
8	Large General Service					
9	10.03	593,356	43,522,724	352	1,685,670	0.0734
10						
11	Real Time Pricing Rider					
12	14.02	55,359	2,043,907	2	27,679,500	0.0369
13						
14	Large Gen. Srv. (Time of Day)					
15	10.05	1,086,946	69,597,994	93	11,687,591	0.0640
16						
17	Large General Service Rider					
18	14.03	147,835	4,884,460	15	9,855,667	0.0330
19						
20	Water Heating Ctrlld (Off-Peak)					
21	14.01	1,918	147,766	485	3,955	0.0770
22				-485		
23	Controlled Service					
24	14.04,14.05,14.06,14.07	190,222	8,848,423	5,000	38,044	0.0465
25				-5,000		
26	Fixed Time of Delivery Service					
27	14.07	22,551	919,555	591	38,157	0.0408
28				-591		
29	Irrigation Service					
30	11.02	4,787	466,001	361	13,260	0.0973
31						
32						
33						
34						
35						
36	Column D Lines 21, 24 & 27					
37	Customers are also served					
38	under other commercial service.					
39						
40						
41	TOTAL Billed	4,784,300	369,805,482	135,460	35,319	0.0773
42	Total Unbilled Rev.(See Instr. 6)	30,684	2,370,805	0	0	0.0773
43	TOTAL	4,814,984	372,176,287	135,460	35,545	0.0773

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	Commercial and Industrial - cntd					
2	Commercial Time of Use					
3	10.03 & 10.04	542,304	43,179,307	599	905,349	0.0796
4						
5	Outdoor Lighting - Energy Only					
6	11.03	1,945	177,983	268	7,257	0.0915
7				-268		
8	Outdoor Lighting					
9	11.04	14,375	2,051,419	253	56,818	0.1427
10				-253		
11	Standby Service - Option A Firm					
12	11.01	122	15,453	5	24,400	0.1267
13						
14	Small Power Producer Rider					
15	12.01	-3	698	26	-115	-0.2327
16				-26		
17						
18	Conservation Imp Prog Rev		-1,903,451			
19	Environmental Rider Rev		-1,037,538			
20	Transmission Cost Recvy		1,583,886			
21	Renewable Resource Rider		-1,139,854			
22	Fuel Clause Adjustment Rec		-5,367,916			
23	Southwest Power Pool Rider		-476,089			
24	EITE Revenue Rider		58,162			
25	SUBTOTAL Billed	3,488,466	251,521,240	29,273	119,170	0.0721
26	Unbilled Rev (See Instr. 6)	18,242	1,326,674			0.0727
27	TOTAL - 442	3,506,708	252,847,914	29,273	119,793	0.0721
28						
29						
30						
31	Column D Lines 6,9 & 15					
32	customers are also served under					
33	other commerical service.					
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	4,784,300	369,805,482	135,460	35,319	0.0773
42	Total Unbilled Rev.(See Instr. 6)	30,684	2,370,805	0	0	0.0773
43	TOTAL	4,814,984	372,176,287	135,460	35,545	0.0773

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	Streetlighting - 444					
2	Outdoor Lighting-Energy Only					
3	11.03	6,501	561,167	280	23,218	0.0863
4				-280		
5	Outdoor lighting					
6	11.04	18,470	3,261,402	343	53,848	0.1766
7						
8	Conservation Imp Prog Rev		-12,103			
9	Environmental Rider Rev		-6,784			
10	Transmission Cost Recvy		14,694			
11	Renewable Resource Rider		-9,566			
12	Fuel Clause Adjustment Rec		-48,988			
13	Southwest Power Pool Rider		-2,249			
14	EITE Revenue Rider		271			
15	Subtotal billed	24,971	3,757,844	343	72,802	0.1505
16	Unbilled Revenue	24	11,330			0.4721
17	TOTAL - 444	24,995	3,769,174	343	72,872	0.1508
18						
19	Other Public Authority-445					
20	Pumping and Sirens					
21	11.05,11.06	39,979	3,184,152	1,285	31,112	0.0796
22						
23	Conservation Imp Prog Rev		-23,642			
24	Environmental Rider Rev		-9,255			
25	Transmission Cost Recvy		24,818			
26	Renewable Resource Rider		-14,385			
27	Fuel Clause Adjustment Rec		-63,376			
28	Southwest Power Pool Rider		-4,570			
29	EITE Revenue Rider		452			
30	Subtotal	39,979	3,094,194	1,285	31,112	0.0774
31	Unbilled Revenue	110	9,952			0.0905
32	TOTAL - 445	40,089	3,104,146	1,285	31,198	0.0774
33						
34	Revenue from Fuel Adjustment					
35	Clause is reported in footnote.					
36						
37	Column D, Line 3					
38	customers are also served under					
39	other commercial service.					
40	MN Interim Rate Refund		-4,982,931			
41	TOTAL Billed	4,784,300	369,805,482	135,460	35,319	0.0773
42	Total Unbilled Rev.(See Instr. 6)	30,684	2,370,805	0	0	0.0773
43	TOTAL	4,814,984	372,176,287	135,460	35,545	0.0773

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Power Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2017	2017/Q4
FOOTNOTE DATA			

Schedule Page: 304 Line No.: 33 Column: a

Energy Intensive Trade Exposed Revenue Rider

Schedule Page: 304.2 Line No.: 24 Column: a

Energy Intensive Trade Exposed Revenue Rider

Schedule Page: 304.3 Line No.: 14 Column: a

Energy Intensive Trade Exposed Revenue Rider

Schedule Page: 304.3 Line No.: 29 Column: a

Energy Intensive Trade Exposed Revenue Rider

Schedule Page: 304.3 Line No.: 34 Column: a

The following revenue received through the fuel adjustment clause is included in the amounts reported on pages 304-304.3.

Residential - 440

9.01	Residential service	\$ 1,104,021
9.02	Residential service (control demand)	44,873
14.01	Water heating - controlled (off-peak)	76,311
14.04,14.05,14.06,14.07	Controlled service	136,029
14.07	Fixed time of delivery service	12,118
11.03	Outdoor lighting- energy only	777
11.04	Outdoor lighting	4,301

Total residential \$ 1,378,430

Commercial and industrial - 442

10.01, 10.02	General service	\$ 685,076
9.03	Farm service	107,765
10.03	Large general service	(1,765,963)
14.02	Real time pricing rider	-
10.05	Large general service (time of day)	29,766
14.03	Large general service rider	4
14.01	Water heating - controlled (off-peak)	7,965
14.04,14.05,14.06,14.07	Controlled service	142,732
14.07	Fixed time of delivery service	33,245
11.02	Irrigation service	(2,134)
10.04	Commercial time of use	4,714,205
11.03	Outdoor lighting - energy only	2,436
11.04	Outdoor lighting	5,273
11.01	Standby service-option A firm	(403)

Total commercial and industrial \$ 3,959,965

Streetlighting - 444

11.03	Outdoor lighting - energy only	\$ 20,780
11.04	Outdoor lighting	5,431

Total streetlighting \$ 26,211

Other public authority - 445

11.05,11.06	Pumping and sirens	\$ 45,986
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Total \$ 5,410,592

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	RQ SALES					
2	Badger, SD	RQ	144	0.312	NA	NA
3	Newfolden, MN	RQ	174	0.460	NA	NA
4	Nielsville, MN	RQ	175	0.031	NA	NA
5	Shelly, MN	RQ	176	0.200	NA	NA
6						
7	NON-RQ SALES					
8	Midwest ISO Energy Market	OS	V9	NA	NA	NA
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

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)		
					1
581	17,082	19,950	4,667	41,699	2
2,145	25,422	74,397	18,112	117,931	3
66	2,032	2,436	560	5,028	4
766	14,004	26,606	6,303	46,913	5
					6
					7
222,049		4,961,533		4,961,533	8
					9
					10
					11
					12
					13
					14
3,558	58,540	123,389	29,642	211,571	
222,049	0	4,961,533	0	4,961,533	
225,607	58,540	5,084,922	29,642	5,173,104	

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 310 Line No.: 2 Column: j

Fuel adjustment charges

Schedule Page: 310 Line No.: 3 Column: j

Fuel adjustment charges

Schedule Page: 310 Line No.: 4 Column: j

Fuel adjustment charges

Schedule Page: 310 Line No.: 5 Column: j

Fuel adjustment charges

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	1,651,107	1,722,605
5	(501) Fuel	58,605,849	53,727,773
6	(502) Steam Expenses	5,817,946	5,627,969
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,441,793	2,309,873
10	(506) Miscellaneous Steam Power Expenses	5,061,938	4,887,525
11	(507) Rents	1,147	4,971
12	(509) Allowances	15,509	28,032
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	73,595,289	68,308,748
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	842,512	861,972
16	(511) Maintenance of Structures	1,202,457	1,150,873
17	(512) Maintenance of Boiler Plant	7,207,759	7,510,932
18	(513) Maintenance of Electric Plant	797,052	1,239,787
19	(514) Maintenance of Miscellaneous Steam Plant	1,063,182	1,354,726
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	11,112,962	12,118,290
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	84,708,251	80,427,038
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	13,178	10,600
45	(536) Water for Power		
46	(537) Hydraulic Expenses	11,472	21,007
47	(538) Electric Expenses	20,477	34,694
48	(539) Miscellaneous Hydraulic Power Generation Expenses	22,132	17,444
49	(540) Rents	107	
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	67,366	83,745
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	3,449	12,385
54	(542) Maintenance of Structures	5,016	1,824
55	(543) Maintenance of Reservoirs, Dams, and Waterways	277,356	284,145
56	(544) Maintenance of Electric Plant	50,242	6,319
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	336,063	304,673
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	403,429	388,418

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	265,030	246,551
63	(547) Fuel	1,484,624	1,422,735
64	(548) Generation Expenses	2,257,201	2,210,732
65	(549) Miscellaneous Other Power Generation Expenses	567,942	701,799
66	(550) Rents	593,392	581,889
67	TOTAL Operation (Enter Total of lines 62 thru 66)	5,168,189	5,163,706
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	85,285	124,683
70	(552) Maintenance of Structures	124,923	34,077
71	(553) Maintenance of Generating and Electric Plant	669,208	518,892
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	32,347	143,507
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	911,763	821,159
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	6,079,952	5,984,865
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	64,807,218	63,225,919
77	(556) System Control and Load Dispatching	590,724	441,055
78	(557) Other Expenses	50,392	54,874
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	65,448,334	63,721,848
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	156,639,966	150,522,169
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	419,482	464,279
84			
85	(561.1) Load Dispatch-Reliability	79,683	71,442
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,534,429	2,471,306
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	1,095,452	1,069,288
89	(561.5) Reliability, Planning and Standards Development	622,440	763,506
90	(561.6) Transmission Service Studies	5,175	140
91	(561.7) Generation Interconnection Studies	152	625
92	(561.8) Reliability, Planning and Standards Development Services	10,000	
93	(562) Station Expenses	297,518	318,041
94	(563) Overhead Lines Expenses	368,841	599,907
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	20,807,504	22,085,013
97	(566) Miscellaneous Transmission Expenses	619,124	656,770
98	(567) Rents	30,063	49,879
99	TOTAL Operation (Enter Total of lines 83 thru 98)	26,889,863	28,550,196
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	207,223	204,233
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	69,822	50,158
104	(569.2) Maintenance of Computer Software	716,648	727,917
105	(569.3) Maintenance of Communication Equipment	90,156	91,267
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,219,312	1,175,177
108	(571) Maintenance of Overhead Lines	1,936,496	1,779,654
109	(572) Maintenance of Underground Lines	14	1,772
110	(573) Maintenance of Miscellaneous Transmission Plant		1,195
111	TOTAL Maintenance (Total of lines 101 thru 110)	4,239,671	4,031,373
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	31,129,534	32,581,569

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation	712,690	716,422
117	(575.3) Transmission Rights Market Facilitation	2,097	2,217
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation	25,022	28,980
120	(575.6) Market Monitoring and Compliance	53,416	66,617
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	793,225	814,236
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software	212,635	216,943
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)	212,635	216,943
131	TOTAL Regional Transmission and Market Op Exps (Total 123 and 130)	1,005,860	1,031,179
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	279,039	277,252
135	(581) Load Dispatching	206,826	224,423
136	(582) Station Expenses	282,504	310,375
137	(583) Overhead Line Expenses	582,917	273,050
138	(584) Underground Line Expenses	1,943,453	1,937,284
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	650,181	840,341
141	(587) Customer Installations Expenses	198,812	215,285
142	(588) Miscellaneous Expenses	3,661,715	3,677,204
143	(589) Rents	228,349	241,832
144	TOTAL Operation (Enter Total of lines 134 thru 143)	8,033,796	7,997,046
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,022,254	823,850
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	730,259	804,090
149	(593) Maintenance of Overhead Lines	4,884,313	4,188,930
150	(594) Maintenance of Underground Lines	1,016,562	1,029,141
151	(595) Maintenance of Line Transformers	93,253	74,444
152	(596) Maintenance of Street Lighting and Signal Systems	1,047,827	1,014,230
153	(597) Maintenance of Meters	800,588	736,064
154	(598) Maintenance of Miscellaneous Distribution Plant	132,993	123,052
155	TOTAL Maintenance (Total of lines 146 thru 154)	9,728,049	8,793,801
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	17,761,845	16,790,847
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	85,145	48,006
160	(902) Meter Reading Expenses	5,976,893	5,743,243
161	(903) Customer Records and Collection Expenses	5,579,346	5,229,744
162	(904) Uncollectible Accounts	750,000	930,000
163	(905) Miscellaneous Customer Accounts Expenses	520,483	525,093
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	12,911,867	12,476,086

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	603,596	595,471
168	(908) Customer Assistance Expenses	8,318,524	9,712,307
169	(909) Informational and Instructional Expenses	414,652	413,306
170	(910) Miscellaneous Customer Service and Informational Expenses	21,515	59,717
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	9,358,287	10,780,801
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	106,971	76,266
175	(912) Demonstrating and Selling Expenses	229,430	262,712
176	(913) Advertising Expenses	1,305	
177	(916) Miscellaneous Sales Expenses	1,569	5,682
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	339,275	344,660
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	23,839,398	22,524,725
182	(921) Office Supplies and Expenses	7,875,309	6,914,141
183	(Less) (922) Administrative Expenses Transferred-Credit	2,103,758	2,472,648
184	(923) Outside Services Employed	1,164,187	1,353,266
185	(924) Property Insurance	1,604,023	3,168,173
186	(925) Injuries and Damages	2,209,606	2,248,103
187	(926) Employee Pensions and Benefits	3,066,245	3,113,201
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	3,754,248	4,390,992
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	405,135	490,312
192	(930.2) Miscellaneous General Expenses	1,976,452	1,539,761
193	(931) Rents	281,269	287,129
194	TOTAL Operation (Enter Total of lines 181 thru 193)	44,072,114	43,557,155
195	Maintenance		
196	(935) Maintenance of General Plant	1,505,044	1,137,692
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	45,577,158	44,694,847
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	274,723,792	269,222,158

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 320 Line No.: 86 Column: b

\$607,221 of the year-to-date expense recorded in Accounts 561 and 569 is designated as Account 561.BA expense.

Schedule Page: 320 Line No.: 86 Column: c

\$601,148 of the year-to-date expense recorded in Accounts 561 and 569 is designated as Account 561.BA expense.

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	Great River Energy	SF		100	NA	NA
2	Great River Energy	SF		80	NA	NA
3	Minnesota Municipal Power Agency	SF		15	NA	NA
4	Minnesota Power	SF		20	NA	NA
5	Northern States Power Company	OS		NA	NA	NA
6	Western Area Power Administration	OS		NA	NA	NA
7	Western Area Power Administration WEC	OS		NA	NA	NA
8	Nebraska Public Power District RLA	OS		NA	NA	NA
9	Beltrami Electric Cooperative	RQ		NA	NA	NA
10	Nodak Rural Electric Cooperative	RQ		NA	NA	NA
11	P K M Electric Cooperative	RQ		NA	NA	NA
12	Red Lake Rural Electric Cooperative	RQ		NA	NA	NA
13	Cass County Electric Cooperative	RQ		NA	NA	NA
14	Whetstone Valley Electric Cooperative	RQ		NA	NA	NA
	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	Prairie Lakes Muni Waste	RQ		NA	NA	NA
2	Dakota Magic Casino	RQ		NA	NA	NA
3	Kindred School	RQ		NA	NA	NA
4	Stevens Community Medical	OS		NA	NA	NA
5	City of Detroit Lakes	OS		NA	NA	NA
6	American Crystal Sugar	OS		NA	NA	NA
7	Dakota Wind Exchange	OS		NA	NA	NA
8	Hendricks Wind I	OS		NA	NA	NA
9	Borderline Wind	OS		NA	NA	NA
10	Univ. of MN - Morris	OS		NA	NA	NA
11	FPL Energy ND II, LLC	OS		NA	NA	NA
12	Langdon Wind, LLC	OS		NA	NA	NA
13	Turtle Mountain Community College	OS		NA	NA	NA
14	LacQui Parle School	OS		NA	NA	NA
	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	Pembina Border Station	OS		NA	NA	NA
2	Lake Region State College	OS		NA	NA	NA
3	Ashtabula Wind III LLC	OS		NA	NA	NA
4	Ashtabula Wind III LLC - Curtailment	OS		NA	NA	NA
5	MN Co Generation	OS		NA	NA	NA
6	ND Co Generation	OS		NA	NA	NA
7	SD Co Generation	OS		NA	NA	NA
8						
9	Midwest ISO Energy Market	OS		NA	NA	NA
10	Southwest Power Pool ISO Energy Market	OS		NA	NA	NA
11	Miscellaneous Energy Market Changes					
12						
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)	
			1,000,000			1,000,000	1
			1,650,250			1,650,250	2
			-67,500			-67,500	3
			266,000			266,000	4
203,200				3,489,738		3,489,738	5
-799				-18,485		-18,485	6
29,870				858,273		858,273	7
				-2,874		-2,874	8
110,805			1,102,159	5,107,986	59,706	6,269,851	9
8,253			87,899	476,683		564,582	10
8,580			108,380	495,403		603,783	11
8,395			107,255	454,925		562,180	12
			5,789			5,789	13
			1,017			1,017	14
2,372,739			4,355,082	60,392,430	59,706	64,807,218	

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)	
			10,560			10,560	1
			29,520			29,520	2
			28,800			28,800	3
			23,760			23,760	4
939			1,193	1,408		2,601	5
2,357				23,571		23,571	6
17				574		574	7
2,353				86,845		86,845	8
2,024				60,716		60,716	9
4,591				252,513		252,513	10
53,133				1,588,678		1,588,678	11
82,210				3,224,259		3,224,259	12
357				11,856		11,856	13
28				932		932	14
2,372,739			4,355,082	60,392,430	59,706	64,807,218	

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)	
1,344				44,731		44,731	1
4,247				134,433		134,433	2
226,978				6,423,990		6,423,990	3
2,688				75,949		75,949	4
188				18,096		18,096	5
80				1,070		1,070	6
42				1,497		1,497	7
							8
1,606,827				38,353,238		38,353,238	9
14,032				-775,052		-775,052	10
				1,477		1,477	11
							12
							13
							14
2,372,739			4,355,082	60,392,430	59,706	64,807,218	

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 326 Line No.: 1 Column: a
January through May 2017

Schedule Page: 326 Line No.: 2 Column: a
June through December 2017

Schedule Page: 326 Line No.: 3 Column: a
January through May 2017

Schedule Page: 326 Line No.: 4 Column: a
June through December 2017

Schedule Page: 326 Line No.: 9 Column: l
Nomination charge

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	Badger, SD	Western Area Power Administration	Badger, SD	LFP
2	Newfolden, MN	Western Area Power Administration	Newfolden, MN	LFP
3	Nielsville, MN	Western Area Power Administration	Nielsville, MN	LFP
4	Shelly, MN	Western Area Power Administration	Shelly, MN	LFP
5	Fort Totten Indian Agency	Western Area Power Administration	Fort Totten, ND	LFP
6	State Development Center	Western Area Power Administration	Grafton, ND	LFP
7	North Dakota School for Deaf	Western Area Power Administration	Devils Lake, ND	LFP
8	North Dakota School of Forestry	Western Area Power Administration	Bottineau, ND	LFP
9	North Dakota College of Science	Western Area Power Administration	Wahpeton, ND	LFP
10	Turtle Mountain Indian Agency	Western Area Power Administration	Belcourt, ND	LFP
11	Oakes O&M Headquarters	Western Area Power Administration	Oakes, ND	LFP
12	Minnkota Power Cooperative, Inc.	Minnkota Power Cooperative, Inc.	Various Interconnects	OS
13		U.S. Bureau of Reclamation	Otter Tail Power Company	OS
14		Various Companies	Otter Tail Power Company	OS
15		Various Companies	Otter Tail Power Company	OS
16	Midwest Independent System Operator	Various Companies	Various Companies	OS
17	See Footnote			
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

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)	
4	(1)	Badger, SD		1,346	1,288	1
4	(1)	Newfolden, MN		2,973	2,778	2
4	(1)	Nielsville, MN		654	611	3
4	(1)	Shelly, MN		1,729	1,616	4
4	(1)	Fort Totten, ND		352	332	5
4	(1)	Grafton, ND		4,718	4,451	6
4	(1)	Devils Lake, ND		480	449	7
4	(1)	Bottineau, ND		1,194	1,116	8
4	(1)	Wahpeton, ND		8,628	8,101	9
4	(1)	Belcourt, ND		2,174	2,051	10
4	(1)	Oakes, ND		62	59	11
See Footnote	(1)	Various Interconnect		236,020	220,579	12
		(1)		1,067		13
		(1)		-290,199		14
		(1)		-1,068		15
OATT	System	System				16
	See Footnote					17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	-29,870	243,431	

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.
9,508			9,508	1
26,064			26,064	2
8,093			8,093	3
16,881			16,881	4
1,389			1,389	5
22,381			22,381	6
6,135			6,135	7
11,325			11,325	8
92,870			92,870	9
23,860			23,860	10
2,014			2,014	11
	225,608		225,608	12
				13
				14
				15
		43,028,603	43,028,603	16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
220,520	225,608	43,028,603	43,474,731	

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) 12/31/2017	Year/Period of Report 2017/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

Schedule Page: 328 Line No.: 12 Column: e

Original Service Agreement No. 30 under Otter Tail Power Company FERC Electric Tariff, Original Volume No. 1

Schedule Page: 328 Line No.: 15 Column: b

Various companies

Miscellaneous losses - mwh received

Schedule Page: 328 Line No.: 16 Column: m

Midwest Independent System Operator Transmission

Schedule 1 Network = 858,009

Schedule 1 Firm = 47,919

Schedule 1 Non-firm = 4,250

Schedule Page: 328 Line No.: 17 Column: a

Lines 1-10 Otter Tail Power Company wheels WAPA's portion of customers' load.

Line 11 Otter Tail Power Company wheels WAPA's total load to customer.

Line 12 Otter Tail Power Company wheels MPC's total load to various interconnects.

Lines 13-15 contain losses and regulation that result from interconnects with various companies in the integrated system.

Schedule Page: 328 Line No.: 17 Column: f

(1) Various points of interconnect in the integrated system

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			
			Megawatt-hours Received (c)	Megawatt-hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	Otter Tail Power Co.	FNS					5,270,812	5,270,812
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL						5,270,812	5,270,812

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 332 Line No.: 1 Column: g

The expenses incurred are for transmission of electricity and supporting services provided by the Midcontinent Independent System Operator and the Southwest Power Pool.

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	247,427
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	112,296
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	214,821
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < \$5,000	54,019
6	Director Fees & Expenses	797,106
7	Misc. Labor not provided for elsewhere	544,283
8	Flag Family Media - Radio program sponsorship	6,500
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
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32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	1,976,452

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			1,609,138		1,609,138
2	Steam Production Plant	15,848,969	123,495			15,972,464
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	515,180				515,180
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	12,102,693	-3,619			12,099,074
7	Transmission Plant	7,392,819				7,392,819
8	Distribution Plant	11,275,012				11,275,012
9	Regional Transmission and Market Operation					
10	General Plant	2,692,397				2,692,397
11	Common Plant-Electric					
12	TOTAL	49,827,070	119,876	1,609,138		51,556,084

B. Basis for Amortization Charges

The \$1,609,138 is amortization of:

Franchises and Consents (302):
 \$ 41,847 for hydro plant license with a remaining life of 4.92 years at a 3.21% rate.

Miscellaneous Intangible Plant (303):
 \$ 1,567,291 for computer software with a 5-year service life at a 20% rate.

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	Big Stone Plant						
14	311	64,117	34.26	-6.00	2.77	SQ	29.32
15	312	155,227	33.69	-6.00	3.06	SQ	29.32
16	314	12,187	43.25	-6.00	1.58	SQ	29.29
17	315	14,924	36.40	-6.00	2.51	SQ	29.31
18	316	1,654	41.96	-6.00	1.96	SQ	29.29
19							
20	Hoot Lake Plant						
21	311 - Units 2, 3	-5	36.71	-12.20	2.22	SQ	5.46
22	312 - Units 2, 3	9,104	14.58	-12.20	6.61	SQ	5.46
23	312.1 - Units 2, 3	3,917	38.28		1.73	SQ	33.91
24	314 - Units 2, 3	877	23.57	-12.20	3.63	SQ	5.46
25	315 - Units 2, 3	141	26.43	-12.20	3.17	SQ	5.46
26	316 - Units 2, 3	252	14.31	-12.10	6.20	SQ	5.46
27							
28	Coyote Plant						
29	311	9,846	52.25	-8.50	1.51	SQ	24.62
30	312	41,338	48.13	-8.50	1.99	SQ	24.63
31	314	11,306	39.15	-8.50	2.24	SQ	24.65
32	315	3,800	48.02	-8.50	1.65	SQ	24.63
33	316	1,104	37.89	-8.20	2.48	SQ	24.65
34							
35	STEAM PROD	329,789					
36							
37	HYDRO PRODUCTION						
38	Hoot Lake Hydro						
39	331	1	61.16		0.24	SQ	5.46
40	332	34	29.89		2.10	SQ	5.46
41	333	8	36.08		1.43	SQ	5.46
42	334	4	30.68		1.96	SQ	5.46
43	335	30	8.91		11.15	SQ	5.46
44							
45	Wright Hydro						
46	331	3	30.68		2.96	SQ	5.46
47	332	489	9.58		10.04	SQ	5.46
48	333	111	9.29		3.72	SQ	5.46
49	334	56	17.78		5.10	SQ	5.46
50	335	51	12.20		8.07	SQ	5.46

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							
13	Pisgah Hydro						
14	331	2	38.70		2.36	SQ	5.46
15	332	157	12.97		7.67	SQ	5.46
16	333	57	15.87		6.59	SQ	5.46
17	334	31	17.73		5.65	SQ	5.46
18	335	40	8.91		11.71	SQ	5.46
19							
20	Dayton Hollow Hydro						
21	331	9	9.93		10.36	SQ	5.46
22	332	714	10.67		10.13	SQ	5.46
23	333	80	14.16		6.49	SQ	5.46
24	334	48	21.32		4.52	SQ	5.46
25	335	66	8.93		10.79	SQ	5.46
26							
27	Taplin Gorge Hydro						
28	331	2	74.27		0.90	SQ	5.45
29	332	202	16.29		6.15	SQ	5.46
30	333	1	81.90		0.78	SQ	5.46
31	334	13	22.15		3.95	SQ	5.46
32	335	48	11.73		8.54	SQ	5.46
33							
34	Bemidji Hydro						
35	331	84	13.18		7.74	SQ	5.46
36	332	368	13.00		8.25	SQ	5.46
37	333	101	19.62		5.74	SQ	5.46
38	334	2	73.00		5.73	SQ	5.45
39	335	1	11.87		9.58	SQ	5.46
40							
41	HYDRO PROD	2,813					
42							
43	OTHER PRODUCTION						
44	Jamestown Peaking #1						
45	341	65	36.90	-1.70	1.46	SQ	17.10
46	342	162	28.19	-1.70	2.59	SQ	17.11
47	343	777	43.53	-1.70	1.60	SQ	17.09
48	345	35	55.62	-1.70	1.41	SQ	17.07
49	346	46	22.30	-1.70	3.21	SQ	17.11
50							

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	Lake Preston Peaking						
13	341	40	41.90	-2.90	1.20	SQ	17.09
14	342	68	39.93	-2.90	1.38	SQ	17.09
15	343	594	48.60	-2.90	1.23	SQ	17.08
16	345	76	51.03	-2.90	1.28	SQ	17.08
17	346	2	48.22	-2.90	0.66	SQ	17.08
18							
19	Jamestown Peaking #2						
20	341	11	27.49	-1.70	2.63	SQ	17.11
21	342	6	35.02	-1.70	1.02	SQ	17.08
22	343	706	47.71	-1.70	1.15	SQ	17.08
23	345	46	21.40	-1.70	3.79	SQ	17.11
24	346		45.86	-1.70	-0.45	SQ	17.09
25							
26	Fergus Falls Ctrl Ctr						
27	343	240	33.99		2.85	SQ	14.22
28							
29	Solway Combust Turbine						
30	341	2,726	32.98	-0.40	2.85	SQ	21.85
31	342	611	33.48	-0.40	2.81	SQ	21.85
32	343	13,514	33.10	-0.40	2.90	SQ	21.85
33	345	851	32.42	-0.40	3.00	SQ	21.85
34	346	231	32.11	-0.40	3.04	SQ	21.85
35							
36	Langdon Wind Energy						
37	341	1,595	24.31	-1.40	4.06	SQ	16.15
38	344	45,763	24.13	-1.40	4.18	SQ	16.15
39	345	4,848	23.82	-1.40	4.14	SQ	16.15
40	346	52	19.39	-1.50	5.05	SQ	16.16
41							
42	Ashtabula Wind Energy						
43	341	2,206	24.29	-1.20	4.04	SQ	17.11
44	344	74,207	24.14	-1.20	4.14	SQ	17.11
45	345	4,326	24.18	-1.20	4.05	SQ	17.11
46	346	23	20.46	-1.20	4.84	SQ	17.11
47							
48	Luverne Wind Energy Ctr						
49	341	1,611	24.27	-2.00	4.04	SQ	18.07
50	344	47,420	24.17	-2.00	4.11	SQ	18.07

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	345	3,458	24.26	-2.00	4.05	SQ	18.07
13	346	63	20.58	-2.00	4.79	SQ	18.07
14							
15	OTHER PROD	206,379					
16							
17	TRANSMISSION PLANT						
18	350.1	13,631			1.43		70.00
19	353	74,006	65.15	-5.00	1.56	R1	53.06
20	354	75,084	70.00	-10.00	1.54	R5	66.45
21	355	63,428	70.36	-50.00	1.96	R2	54.30
22	356	68,383	70.23	-30.00	1.70	R2	55.22
23	358	5	42.08	-5.00	1.22	S4	9.36
24	SUBTOTAL	294,537					
25							
26	DISTRIBUTION PLANT						
27	362	56,703	40.63	5.00	2.10	SC	32.11
28	364	30,179	68.09	-75.00	2.47	R3	47.61
29	365	10,270	65.21	-100.00	2.77	R2.5	43.53
30	367	39,146	39.95	-5.00	2.35	R4	24.39
31	368	79,768	40.13	50.00	1.24	R2.5	28.21
32	369	-2,070	55.23	-150.00	4.16	S5	32.19
33	369.1	23,490	45.15	-20.00	2.58	R4	29.99
34	370	16,589	29.71		3.23	L0.5	20.69
35	370.1	1,382	12.31		7.52	R5	2.12
36	370.2		5.00		20.00	SQ - Amortized	1.00
37	371.2	3,740	23.17	10.00	4.05	L0	16.83
38	373	2,612	22.55	-5.00	3.51	L0.5	15.03
39	SUBTOTAL	261,809					
40							
41	GENERAL PLANT						
42	390	14,207	47.53	10.00	2.01	R1.5	30.54
43	390.1	3,245	32.96	49.60	0.50	SQ	14.22
44	390.2	432	27.31	33.60	1.33	SQ	9.38
45	390.3	2,229	49.71	92.60	-1.96	SQ	18.98
46	391	413	15.00		6.67	SQ - Amortized	5.51
47	391.1	213	10.00		10.00	SQ - Amortized	3.46
48	391.2	117	10.00		10.00	SQ - Amortized	4.44
49	391.5	1,187	5.00		20.00	SQ - Amortized	2.52
50	391.6	382	5.00		20.00	SQ - Amortized	2.13

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	15,244					
13	Aircraft	1,010	7.00	39.00			
14	Autos		5.00	15.00			
15	Light Trucks		10.00	10.00			
16	Heavy Trucks & Semi		10.00	15.00			
17	Tractors (includes		10.00	15.00			
18	Cranes)						
19	Trailers		15.00	10.00			
20	Portable Oil Purifier		10.00	20.00			
21	Trenchers		10.00	10.00			
22	Misc. Light Equipment		10.00	10.00			
23	Misc. Heavy Equipment		15.00	15.00			
24	394	2,315	15.00		6.67	SQ - Amortized	8.83
25	394.2	237	15.00		6.67	SQ - Amortized	6.84
26	395		15.00		6.67	SQ - Amortized	
27	396	450	26.23	20.00	3.14	L0	16.89
28	397	450	15.00		6.67	SQ - Amortized	8.90
29	397.1	490	10.00		10.00	SQ - Amortized	4.83
30	397.2	2,414	15.00		6.67	SQ - Amortized	7.69
31	397.3	155	10.00		10.00	SQ - Amortized	5.40
32	397.4	996	40.35	5.00	1.98	R3	24.13
33	SUBTOTAL	46,186					
34							
35	TOTAL	1,141,513					
36							
37	SUBACCOUNTS USED						
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							
49							
50							

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Power Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2017	2017/Q4
FOOTNOTE DATA			

Schedule Page: 336.4 Line No.: 37 Column: a

SUBACCOUNTS USED

- 312.1 Ash Landfills
- 350.1 Easements
- 369.1 Underground Services
- 370.1 Load Management Switches
- 370.2 Interruption Monitors
- 371.2 All Other Private Lighting
- 390.1 General Office Building
- 390.2 Fleet Service Center Building
- 390.3 Central Stores Building
- 391.1 Office Equipment
- 391.2 Duplicating Equipment
- 391.5 Computer Systems
- 391.6 Computer Related Equipment
- 394.2 AMR Equipment
- 397.1 Radio Telecommunication Equipment
- 397.2 Microwave Equipment
- 397.3 Radio Load Control Equipment
- 397.4 Communication Towers

Column (b) is the balance of plant in service (except land) at the beginning of the year, less the associated reserve for accumulated depreciation, and includes amounts tentatively classified in Account 106, Completed Construction Not Classified.

Column (e) rates are applied to the original cost per books (Accounts 101 and 106) at the close of the prior month except when major additions and retirements occur which significantly affect depreciation expense.

Column (d) factors are a composite of rates allowed in the jurisdictions served.

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	Regulatory Agency Assessments:				
2	MN Dept. of Commerce/Public Util. Commission	1,255,173		1,255,173	
3					
4	SD Public Utilities Commission	60,346		60,346	
5					
6	ND Public Service Commission	169,759		169,759	
7					
8	Federal Energy Regulatory Commission	519,019		519,019	
9					
10	Other Expenses:				
11	MN Public Utilities Commission:				
12	E017/GR-15-1033 (MN Rate Case)		971,075	971,075	
13	Miscellaneous		95,551	95,551	
14					
15	ND Public Service Commission:				
16	PU-17-398 ND Rate Case		201,206	201,206	
17	Miscellaneous		12,849	12,849	
18					
19	SD Public Utilities Commission:				
20	Miscellaneous		3,256	3,256	
21					
22	FERC				
23	ER16-209 (Integration of CPEC into SPP)		54,574	54,574	
24	ER17-2042/ER17-906 (Participation in OTP				
25	SPP NITSA/NOA proceedings)		50,051	50,051	
26	FERC Filing Requirements*		227,718	227,718	
27	Miscellaneous		133,671	133,671	
28					
29					
30	* Outside regulatory counsel fees and expenses				
31	for expert review and the resulting corrective				
32	filings following an extensive review of the				
33	company's transmission related agreements.				
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	2,004,297	1,749,951	3,754,248	

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				Line No.
CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	
Department (f)	Account No. (g)	Amount (h)					
							1
Electric	928	1,255,173					2
							3
Electric	928	60,346					4
							5
Electric	928	169,759					6
							7
Electric	928	519,019					8
							9
							10
							11
Electric	928	971,075	1,081,589		814,570	267,019	12
Electric	928	95,551					13
							14
							15
Electric	928	201,206	309,293			309,293	16
Electric	928	12,849					17
							18
							19
Electric	928	3,256					20
							21
							22
Electric	928	54,574					23
							24
Electric	928	50,051					25
Electric	928	227,718					26
Electric	928	133,671					27
							28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		3,754,248	1,390,882		814,570	576,312	46

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	Electric Utility R&D	
2		
3	PERFORMED INTERNALLY:	
4	Other	Miscellaneous
5	Other	Miscellaneous
6	Other	Miscellaneous
7		
8	Sub-Total Performed Internally	
9		
10	PERFORMED EXTERNALLY:	
11		Burns & McDonnell
12		Chartwell Inc
13		E Source Companies LLC
14		
15		
16	Sub-Total Performed Externally	
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35	SUM OF ABOVE	
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)		
					1
					2
					3
18,664		920	18,664		4
100		930.2	100		5
549		921.0	549		6
					7
19,313			19,313		8
					9
					10
	18,407	506	18,407		11
	10,271	930.2	10,271		12
	20,362	930.2	20,362		13
					14
					15
	49,040		49,040		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
19,313	49,040		68,353		35
					36
					37
					38

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminating and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	72,578,495		72,578,495
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	19,545,265		19,545,265
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	19,545,265		19,545,265
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,894		2,894
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,894		2,894
77	Other Accounts (Specify, provide details in footnote):			
78	Fuel Stock (151)	54,174		54,174
79	Miscellaneous Deferred Debits (186)	1,311,346		1,311,346
80	Other Electric Revenue (456)	319,826		319,826
81	Expenses of Nonutility Operations (417.1)	130,903		130,903
82	Expenses for Certain Civic, Political & Related Activity (426)	120,470		120,470
83	Other Deductions (426.5)	192,494		192,494
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	2,129,213		2,129,213
96	TOTAL SALARIES AND WAGES	94,255,867		94,255,867

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 354 Line No.: 77 Column: a

Salaries and wages are included in the specified accounts because they are either not provided for elsewhere, are nonutility in nature, or are nonoperating.

Name of Respondent Otter Tail Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report End of <u>2017/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.

Name of Respondent
Otter Tail Power Company

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

Date of Report
(Mo, Da, Yr)
12/31/2017

Year/Period of Report
End of 2017/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8	Not available				
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
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28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent
Otter Tail Power Company

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

Date of Report
(Mo, Da, Yr)
12/31/2017

Year/Period of Report
End of 2017/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

- (1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
 (2) Report on Column (b) by month the transmission system's peak load.
 (3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
 (4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

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	894	13	10	893	1				
2	February	858	9	8	857	1				
3	March	832	10	9	831	1				
4	Total for Quarter 1				2,581	3				
5	April	666	27	9	665	1				
6	May	601	1	11	600	1				
7	June	641	5	16	640	1				
8	Total for Quarter 2				1,905	3				
9	July	709	5	16	708	1				
10	August	657	1	16	656	1				
11	September	687	12	16	686	1				
12	Total for Quarter 3				2,050	3				
13	October	767	31	9	766	1				
14	November	803	9	9	802	1				
15	December	920	27	9	919	1				
16	Total for Quarter 4				2,487	3				
17	Total Year to Date/Year				9,023	12				

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 400 Line No.: 9 Column: b

Due to meter data corrections, the monthly peak MW for July through September have changed. In some cases the monthly peak day, peak hour, firm network service for self, and firm network service for others may have changed.

Schedule Page: 400 Line No.: 13 Column: b

The peak numbers for October through December are estimated and are from MISO's S-55 settlement data.

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: Not applicable

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									

Name of Respondent

Otter Tail Power Company

This Report Is:

(1) An Original(2) A Resubmission

Date of Report

(Mo, Da, Yr)

12/31/2017

Year/Period of Report

End of 2017/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	4,814,984
3	Steam	2,360,468	23	Requirements Sales for Resale (See instruction 4, page 311.)	3,558
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	222,049
5	Hydro-Conventional	25,128	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	11,819
7	Other	546,049	27	Total Energy Losses	-21,327
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	5,031,083
9	Net Generation (Enter Total of lines 3 through 8)	2,931,645			
10	Purchases	2,372,739			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	-29,870			
17	Delivered	243,431			
18	Net Transmission for Other (Line 16 minus line 17)	-273,301			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	5,031,083			

Name of Respondent Otter Tail Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report End of <u>2017/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:

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	490,504	15,931	894	13	1000
30	February	442,359	8,816	858	9	800
31	March	486,734	14,784	832	10	900
32	April	336,085	12,737	666	27	900
33	May	436,220	18,433	601	1	1100
34	June	374,822	22,965	641	5	1600
35	July	376,141	26,321	709	5	1600
36	August	386,967	10,439	657	1	1600
37	September	411,774	26,576	687	12	1600
38	October	379,224	27,800	767	31	900
39	November	427,800	22,459	803	9	900
40	December	482,453	14,788	920	27	900
41	TOTAL	5,031,083	222,049			

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 401 Line No.: 16 Column: b

Includes interchange transactions and losses thereon.

Schedule Page: 401 Line No.: 17 Column: b

Includes interchange transactions and losses thereon.

Schedule Page: 401 Line No.: 27 Column: b

Includes all retail, wholesale, and transmission wheeling service system losses, losses on other systems due to sales for resale, and inadvertent energy imbalances.

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: Coyote (b)			Plant Name: Big Stone (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1981			1975		
4	Year Last Unit was Installed	1981			1975		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	144.90			223.15		
6	Net Peak Demand on Plant - MW (60 minutes)	150			257		
7	Plant Hours Connected to Load	7451			7768		
8	Net Continuous Plant Capability (Megawatts)	150			258		
9	When Not Limited by Condenser Water	150			258		
10	When Limited by Condenser Water	150			258		
11	Average Number of Employees	80			82		
12	Net Generation, Exclusive of Plant Use - KWh	920450531			1191962246		
13	Cost of Plant: Land and Land Rights	713587			374603		
14	Structures and Improvements	34345882			85343127		
15	Equipment Costs	141284603			241739780		
16	Asset Retirement Costs	1377063			896678		
17	Total Cost	177721135			328354188		
18	Cost per KW of Installed Capacity (line 17/5) Including	1226.5089			1471.4505		
19	Production Expenses: Oper, Supv, & Engr	658763			623168		
20	Fuel	21414875			27280479		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	2090396			2372053		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	597848			830755		
26	Misc Steam (or Nuclear) Power Expenses	619237			2529090		
27	Rents	73			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	294736			371806		
30	Maintenance of Structures	263602			665261		
31	Maintenance of Boiler (or reactor) Plant	2687398			2919104		
32	Maintenance of Electric Plant	292656			434566		
33	Maintenance of Misc Steam (or Nuclear) Plant	422300			334883		
34	Total Production Expenses	29341884			38361165		
35	Expenses per Net KWh	0.0319			0.0322		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil		Coal	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		Tons	Barrels	
38	Quantity (Units) of Fuel Burned	755193	9997	0	772532	2104	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	6948	140000	0	8255	140000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	27.743	71.778	0.000	36.354	71.860	0.000
41	Average Cost of Fuel per Unit Burned	27.474	66.822	0.000	36.970	69.550	0.000
42	Average Cost of Fuel Burned per Million BTU	1.977	11.364	0.000	2.239	11.828	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.023	0.000	0.000	0.023	0.000	0.000
44	Average BTU per KWh Net Generation	11508.000	0.000	0.000	10980.000	0.000	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: <i>Solway</i> (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Gas Turbine	
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	
3	Year Originally Constructed	2003	
4	Year Last Unit was Installed	2003	
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	44.50	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	49	0
7	Plant Hours Connected to Load	1064	0
8	Net Continuous Plant Capability (Megawatts)	44	0
9	When Not Limited by Condenser Water	44	0
10	When Limited by Condenser Water	44	0
11	Average Number of Employees	2	0
12	Net Generation, Exclusive of Plant Use - KWh	35913464	0
13	Cost of Plant: Land and Land Rights	89809	0
14	Structures and Improvements	4411779	0
15	Equipment Costs	24166632	0
16	Asset Retirement Costs	0	0
17	Total Cost	28668220	0
18	Cost per KW of Installed Capacity (line 17/5) Including	644.2297	0
19	Production Expenses: Oper, Supv, & Engr	142	0
20	Fuel	1131464	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	272522	0
26	Misc Steam (or Nuclear) Power Expenses	148220	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	19532	0
30	Maintenance of Structures	16182	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	457057	0
33	Maintenance of Misc Steam (or Nuclear) Plant	9402	0
34	Total Production Expenses	2054521	0
35	Expenses per Net KWh	0.0572	0.0000
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Natural Gas	Oil
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MMBTU	Barrels
38	Quantity (Units) of Fuel Burned	378331	9
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	377255	140000
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	2.987	0.000
41	Average Cost of Fuel per Unit Burned	2.989	94.500
42	Average Cost of Fuel Burned per Million BTU	2.989	16.071
43	Average Cost of Fuel Burned per KWh Net Gen	0.032	0.000
44	Average BTU per KWh Net Generation	10536.000	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>Hoot Lake</i> (d)			Plant Name: <i>Jamestown</i> (e)			Plant Name: <i>Lake Preston</i> (f)			Line No.
	Steam			Gas Turbine			Gas Turbine		1
	Conventional			Conventional			Conventional		2
	1959			1976			1978		3
	1964			1978			1978		4
	128.50			48.11			24.10		5
	144			43			23		6
	5837			69			47		7
	140			43			20		8
	140			43			20		9
	140			43			20		10
	35			1			0		11
	248054900			387844			380321		12
	565967			24614			12339		13
	6088767			305657			229834		14
	64074434			7684747			4033048		15
	484409			0			0		16
	71213577			8015018			4275221		17
	554.1913			166.5978			177.3951		18
	295315			1040			770		19
	8302782			211715			141445		20
	0			0			0		21
	1260893			0			0		22
	0			0			0		23
	0			0			0		24
	1005626			56414			24454		25
	1010572			522			146		26
	1074			0			0		27
	15509			0			0		28
	179713			43958			19078		29
	272336			62817			45921		30
	1592691			0			0		31
	69494			118437			61946		32
	281487			-750			0		33
	14287492			494153			293760		34
	0.0576			1.2741			0.7724		35
Coal	Oil		Oil			Oil			36
Tons	Barrels		Barrels			Barrels			37
157833	4600	0	1990	0	0	1489	0	0	38
9024	140000	0	140000	0	0	140000	0	0	39
48.764	77.910	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
49.181	76.940	0.000	130.032	0.000	0.000	94.960	0.000	0.000	41
2.725	13.085	0.000	22.114	0.000	0.000	16.150	0.000	0.000	42
0.029	0.000	0.000	0.546	0.000	0.000	0.372	0.000	0.000	43
11601.000	0.000	0.000	30176.000	0.000	0.000	23021.000	0.000	0.000	44

Name of Respondent
Otter Tail Power Company

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

Date of Report
(Mo, Da, Yr)
12/31/2017

Year/Period of Report
End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35
			36
			37
0	0	0	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
Otter Tail Power Company

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (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 Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 402 Line No.: -1 Column: b

Coyote - Joint facility operated by Otter Tail Power Company

Schedule Page: 402 Line No.: -1 Column: c

Big Stone - Joint facility operated by Otter Tail Power Company

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: Not applicable (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

Name of Respondent
Otter Tail Power Company

This Report Is:
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Date of Report
(Mo, Da, Yr)
12/31/2017

Year/Period of Report
End of 2017/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
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0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent Otter Tail Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report End of <u>2017/Q4</u>
------------------------------------------------	-----------------------------------------------------------------------------------------------------------------------	----------------------------------------------	------------------------------------------------

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)	0 Not applicable
1	Type of Plant Construction (Conventional or Outdoor)		
2	Year Originally Constructed		
3	Year Last Unit was Installed		
4	Total installed cap (Gen name plate Rating in MW)		
5	Net Peak Demand on Plant-Megawatts (60 minutes)		
6	Plant Hours Connect to Load While Generating		
7	Net Plant Capability (in megawatts)		
8	Average Number of Employees		
9	Generation, Exclusive of Plant Use - Kwh		
10	Energy Used for Pumping		
11	Net Output for Load (line 9 - line 10) - Kwh		
12	Cost of Plant		
13	Land and Land Rights		
14	Structures and Improvements		
15	Reservoirs, Dams, and Waterways		
16	Water Wheels, Turbines, and Generators		
17	Accessory Electric Equipment		
18	Miscellaneous Powerplant Equipment		
19	Roads, Railroads, and Bridges		
20	Asset Retirement Costs		
21	Total cost (total 13 thru 20)		
22	Cost per KW of installed cap (line 21 / 4)		
23	Production Expenses		
24	Operation Supervision and Engineering		
25	Water for Power		
26	Pumped Storage Expenses		
27	Electric Expenses		
28	Misc Pumped Storage Power generation Expenses		
29	Rents		
30	Maintenance Supervision and Engineering		
31	Maintenance of Structures		
32	Maintenance of Reservoirs, Dams, and Waterways		
33	Maintenance of Electric Plant		
34	Maintenance of Misc Pumped Storage Plant		
35	Production Exp Before Pumping Exp (24 thru 34)		
36	Pumping Expenses		
37	Total Production Exp (total 35 and 36)		
38	Expenses per KWh (line 37 / 9)		

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: (c)	0	FERC Licensed Project No. Plant Name: (d)	0	FERC Licensed Project No. Plant Name: (e)	0	Line No.
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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	Hydro:					
2	Hoot Lake	1914	0.67	0.8	5,591	661,464
3	Wright	1922	0.40	0.5	2,841	1,778,450
4	Pisgah	1917	0.65	0.7	5,110	714,887
5	Dayton Hollow	1909	0.97	1.0	8,038	1,864,753
6	Taplin Gorge	1925	0.56	0.3	3,548	966,267
7	Bemidji	1941	0.62			1,356,162
8						
9	Internal Combustion:					
10	Fergus Falls Control Center	1995	1.83	2.1	21	591,638
11	Diesel Generators		2.26	1.6		
12						
13	Wind Turbine Plants					
14	Langdon	2007	40.50	40.4	161,593	79,304,964
15	Ashtabula	2008	48.00	48.3	161,449	116,281,451
16	Luverne	2009	49.50	50.0	186,304	73,074,365
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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
832,031	5,401		26,582	-		2
3,614,737	4,459		52,285	-		3
957,010	3,632		40,242	-		4
1,781,044	3,534		67,795	-		5
3,618,976	3,388		49,984	-		6
	1,883		99,127	-		7
						8
						9
281,732	1,630		7,946	Oil		10
				Oil		11
						12
						13
1,963,480	915,614		4,418			14
2,409,030	735,270		19,460			15
1,460,523	734,246		4,412			16
						17
						18
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Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 410 Line No.: 11 Column: b
 Various.

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	Alexandria	MN Border	345.00	345.00	Steel Tower	101.00		1
2	Big Stone South	Brookings	345.00	345.00	Steel Tower	72.00		1
3	Brookings	MN Border	345.00	345.00	Steel Tower	10.00		1
4	Cedar Mountain	Helena	345.00	345.00	Steel Tower	73.00		2
5	Cedar Mountain	Lyon County	345.00	345.00	Steel Tower	49.00		2
6	Center	Maple River	345.00	345.00	Alum Tower	48.00		1
7	Chub Lake	Hampton	345.00	345.00	Steel Tower	18.00		1
8	Chub Lake	Helena	345.00	345.00	Steel Tower	21.00		1
9	Hazel Creek	Lyon County	345.00	345.00	Steel Tower	25.00		1
10	Lyon County	MN Border	345.00	345.00	Steel Tower	49.00		1
11	MN Border	Bison	345.00	345.00	Steel Tower	35.00		1
12	Monticello	Quarry Sub	345.00	345.00	Steel Tower	29.00		1
13	St Cloud	Alexandria	345.00	345.00	Steel Tower	77.00		1
14								
15	Fergus Falls	Inman	230.00	230.00	Wood H	19.00		1
16	Fergus Falls	Wahpeton	230.00	230.00	Wood H	29.00		1
17	Wahpeton	Hankinson	230.00	230.00	Wood H	26.00		1
18	Hankinson	Forman	230.00	230.00	Wood H	36.00		1
19	Forman	Ellendale	230.00	230.00	Wood H	47.00		1
20	Audubon (W 1/10)	Badoura	230.00	230.00	Wood H	6.00		1
21	Audubon	Sheyenne	230.00	230.00	Wood H	42.00		1
22	Winger (E 1/3)	Wilton	230.00	230.00	Alum Tower	18.00		1
23	Grand Forks (M 1/3)	Winnipeg	230.00	230.00	Wood H	27.00		1
24	Big Stone (N 1/3)	Hankinson	230.00	230.00	Wood H	23.00		1
25	Big Stone (S 1/4)	Blair	230.00	230.00	Wood H	15.00		1
26	Harvey	Coal Creek	230.00	230.00	Wood H	75.00		1
27	Balta	Harvey	230.00	230.00	Wood H	22.00		1
28	Rugby	Balta	230.00	230.00	Steel H	18.00		1
29	Wilton	Cass Lake	230.00	230.00	Steel H	19.00		1
30	Cass Lake	Boswell	230.00	230.00	Steel H	51.00		1
31	Hazel Creek	MN Valley	230.00	345.00	Steel Tower	5.00		1
32	Big Stone Plant	Big Stone South	230.00	230.00	Steel Tower	3.00		1
33		Total	115.00	115.00	Wood H	459.00		
34		Total	115.00	115.00	SWP	415.00		
35		Total	115.00	115.00	Steel Tower	4.00		
36					TOTAL	5,938.00		33

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		Total	69.00	69.00		209.00		
2		Total	41.60	41.60	SWP	3,762.00		
3		Total	41.60	41.60	Underground	1.00		
4								
5								
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35								
36					TOTAL	5,938.00		33

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)	
	2,909,029	30,060,206	32,969,235					1
		53,224,771	53,224,771					2
	92,896	1,045,848	1,138,744					3
	1,366,911	6,381,734	7,748,645					4
	483,587	3,981,603	4,465,190					5
		5,458,744	5,458,744					6
	491,744	2,424,441	2,916,185					7
	869,662	2,150,888	3,020,550					8
	155,112	2,003,998	2,159,110					9
	129,317	3,735,690	3,865,007					10
	616,249	8,168,866	8,785,115					11
	2,259,098	8,201,360	10,460,458					12
	2,679,996	23,297,152	25,977,148					13
								14
		2,024,040	2,024,040					15
		2,198,157	2,198,157					16
		1,273,119	1,273,119					17
	2,160	1,579,053	1,581,213					18
		4,883,130	4,883,130					19
		414,677	414,677					20
		1,690,121	1,690,121					21
		1,852,883	1,852,883					22
		913,195	913,195					23
		803,584	803,584					24
		867,131	867,131					25
		10,672,352	10,672,352					26
		4,433,901	4,433,901					27
		3,486,133	3,486,133					28
	489,732	4,363,737	4,853,469					29
	567,058	10,910,674	11,477,732					30
	47,636	704,667	752,303					31
		2,241,161	2,241,161					32
	13,776	13,649,265	13,663,041					33
	994,389	29,735,796	30,730,185					34
	15,604	187,161	202,765					35
	14,237,397	364,188,115	378,425,512	5,748,584	2,034,813	30,063	7,813,460	36

Name of Respondent
Otter Tail Power Company

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

Date of Report
(Mo, Da, Yr)
12/31/2017

Year/Period of Report
End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

- 7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
- 8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
- 9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
- 10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (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)	
	53,441	7,252,404	7,305,845					1
		107,839,012	107,839,012					2
		77,461	77,461					3
				5,748,584	2,034,813	30,063	7,813,460	4
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	14,237,397	364,188,115	378,425,512	5,748,584	2,034,813	30,063	7,813,460	36

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 422.1 Line No.: 4 Column: m
Columns m, n, and o detail by line not available.

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	Crookston 115 kV	Crookston Plant Junction	1.00	Single pole	20.00	41	
2							
3	Karlstad	Halma	5.00	Single pole	19.40	41	
4							
5	Donaldson	Hallock	7.00	Single pole	20.00	41	
6							
7	Hankinson Casino SW 426	East River Victor SW 474	4.00	3102 Wood pole	23.00	41	
8							
9	Turtle Lake ND	Mercer ND	1.00	Wood pole	24.00	1	
10							
11	Grafton ND	Drayton ND	1.00	Wood pole	21.00	1	
12							
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43							
44	TOTAL		19.00		127.40	166	

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)	
266R	ACSR	3102	41	20,218	171,451	155,123	3,477	350,269	1
									2
1/0R	ACSR	3102	41		204,561	73,915	38,232	316,708	3
									4
3/0R	ACSR	3102	41		142,690	157,079	22,829	322,598	5
									6
3/0R	ACSR	3102	41	31,090	472,446	278,661	55,511	837,708	7
									8
1/0R	T2 ACSR	3102	41		123,738	89,603	31,904	245,245	9
									10
1/0R	T2 ACSR	3102	41		53,540	71,195	-122,456	2,279	11
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				51,308	1,168,426	825,576	29,497	2,074,807	44

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	Transmission Subs 10,000 kva or higher				
2	Bemidji, MN - 115 kv - 63246	Transmission	115.00	69.00	13.20
3	Big Stone 230 kv - 620314	Transmission	230.00	115.00	13.80
4	Big Stone, SD Highway 12 - 63215	Transmission	115.00	41.60	
5	Big Stone South - 620417	Transmission	345.00	230.00	34.50
6	Browns Valley, MN - 230 kv (Peever) - 63325	Transmission	230.00	41.60	
7	Buffalo, ND - 345 kv - 63258	Transmission	345.00	115.00	43.00
8	Canby, MN - 115 kv - 63211	Transmission	115.00	41.60	
9	Cass Lake, MN - 230 kv - 620447	Transmission	230.00	115.00	13.80
10	Cass Lake, MN - 115 kv - 63347	Transmission	115.00	69.00	41.60
11	Clearbrook, MN - 115 kv - 63241	Transmission	115.00	41.60	
12	Crookston, MN - 115 kv - 63249	Transmission	115.00	41.60	
13	Devils Lake, ND - East 115 kv - 63265	Transmission	115.00	41.60	
14	Devils Lake, ND - SW 115 kv - 224	Transmission	115.00	41.60	
15	Donaldson, MN - 115 kv - 63255	Transmission	115.00	41.60	
16	Fergus Falls, MN - Hoot Lake 115 kv - 63223	Transmission	115.00	43.80	
17	Fertile, MN - 115 kv - 63250	Transmission	115.00	41.60	
18	Finley, ND - Pickert 115 kv - 711	Transmission	230.00	72.00	41.60
19	Forman, ND - Forman 230 kv - 63363	Transmission	230.00	115.00	41.60
20	Hensel, ND - 115 kv - 63157	Transmission	115.00	72.00	43.80
21	Hetland, SD - 115 kv - 63209	Transmission	115.00	41.60	
22	Jamestown, ND - 345 kv - 63369	Transmission	345.00	115.00	43.00
23	Jamestown, ND - Peaking Plant 115 kv - 63272	Transmission	115.00	41.60	
24	Maple River, ND - 345 kv - 66792	Transmission	345.00	230.00	13.80
25	Mapleton, ND - 115 kv - 63203	Transmission	115.00	41.60	
26	Marietta, MN - 115 kv - 63213	Transmission	115.00	41.60	
27	Northwoods, MN - 115kv - 63282	Transmission	115.00	41.60	
28	Oakes, ND - 230 kv - 63362	Transmission	230.00	41.60	
29	Ortonville, MN - 115 kv - 63216	Transmission	115.00	41.60	
30	Pelican Rapids, MN - 115 k - 63234	Transmission	115.00	41.60	
31	Plummer, MN - 115kv - 7967	Transmission	115.00	41.60	
32	Rugby, ND - 230 kv - 63373	Transmission	230.00	115.00	13.80
33	Rugby, ND - 230 kv - 63373	Transmission	230.00	115.00	41.60
34	Spiritwood, ND	Transmission	115.00	41.60	
35	Toronto, SD - 115 kv - 63210	Transmission	115.00	41.60	
36	Wahpeton Inventory (came from Cass Lake)	Transmission	115.00	69.00	41.60
37	Wahpeton Inventory	Transmission	345.00	115.00	43.00
38	WAPA Summit, ND	Transmission	115.00	41.60	
39	Winger, MN 63238	Transmission	230.00	115.00	13.20
40	Subtotal:		6555.00	2763.40	496.90

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					
2	Transmission Subs Under 10,000 kva				
3	Colgate	Transmission	69.00	43.80	12.50
4	Green Valley	Transmission	67.00	41.60	
5	Lake Preston	Transmission	69.00	44.00	
6	St Vincent	Transmission	69.00	41.60	
7	Wahpeton Inventory	Transmission	69.00	41.60	
8	Total:		6898.00	2976.00	509.40
9					
10	Distribution Subs 10,000 kva or higher				
11	Bemidji, MN 25th Street	Distribution	69.00	12.50	
12	Bemidji, MN Airport	Distribution	41.60	12.50	
13	Bemidji, MN Nymore	Distribution	69.00	12.50	
14	Bemidji, MN Industrial Park	Distribution	69.00	12.50	
15	Bottineau, ND Downtown	Distribution	41.60	12.50	
16	Casselton, ND	Distribution	41.60	12.50	
17	Casselton, ND Ethanol plant	Distribution	115.00	12.50	
18	Clearbrook, MN Pipeline	Distribution	115.00	4.16	
19	Cooperstown, ND	Distribution	41.60	12.50	
20	Crookston, MN Parkview	Distribution	41.60	12.50	
21	Crookston, MN South Main	Distribution	41.60	12.50	
22	Dawson, MN Dawson Mills	Distribution	115.00	12.50	
23	Devils Lake, ND Downtown	Distribution	41.60	4.16	
24	Enderlin, ND	Distribution	115.00	12.50	
25	Fairmount, ND	Distribution	115.00	12.50	
26	Fergus Falls, MN Edgetown	Distribution	115.00	12.50	
27	Fergus Falls, MN Hoot Lake	Distribution	115.00	12.50	
28	Fergus Falls, MN South East	Distribution	115.00	12.50	
29	Gwinner, ND	Distribution	115.00	12.50	
30	Harvey, ND Northwest	Distribution	115.00	12.50	
31	Itasca, MN Minnesota Pipeline	Distribution	115.00	4.16	
32	Jamestown, ND Downtown	Distribution	115.00	12.50	
33	Jamestown, ND North	Distribution	115.00	12.50	
34	Jamestown, ND Potato	Distribution	115.00	12.50	
35	Jamestown, ND Southwest	Distribution	41.60	12.50	
36	Lake Norden, SD Dairy	Distribution	41.60	12.50	
37	Lisbon, ND Town	Distribution	115.00	12.50	
38	Mahnomen, MN	Distribution	115.00	12.50	
39	Milbank, SD Northwest	Distribution	41.60	12.50	
40	Milbank, SD South	Distribution	41.60	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	Morris, MN Northeast	Distribution	41.60	12.50	
2	Morris, MN South	Distribution	115.00	12.50	
3	Oakes, ND North	Distribution	41.60	12.50	
4	Parkers Prairie	Distribution	41.60	12.50	
5	Pelican Rapids, MN Turkey Plant	Distribution	115.00	12.50	
6	Perham, MN	Distribution	115.00	12.50	
7	Rosholt, SD	Distribution	41.60	12.50	
8	Rugby, ND South	Distribution	41.60	12.50	
9	Spiritwood, ND	Distribution	115.00	12.50	
10	Wahpeton Inventory	Distribution	115.00	12.50	
11	Wahpeton Inventory	Distribution	115.00	4.16	
12	Wahpeton Inventory	Distribution	41.60	12.50	
13	Wahpeton Inventory	Distribution	41.60	4.16	
14	Wahpeton, ND North 115 kv - 63230	Distribution	115.00	12.50	
15	Wahpeton, ND Northwest	Distribution	41.60	12.50	
16	Wheaton, MN South	Distribution	115.00	12.50	
17	Distribution Subtotal:		3757.40	533.30	
18					
19	Distribution Under 10,000 kva	Distribution			
20	Distribution Total		3757.40	533.30	
21	Transmission From Above		6898.00	2976.00	510.00
22	Transmission & Distribution		10655.40	3509.30	510.00
23					
24					
25					
26					
27					
28					
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)	
						1
19	1					2
233	1					3
45	1					4
896	2					5
26	1					6
224	2					7
27	1					8
187	1					9
40	1					10
13	1					11
95	2					12
34	1					13
57	1					14
20	2					15
30	1					16
10	1					17
60	1					18
140	1					19
55	1					20
45	1					21
672	2					22
56	1					23
672	2					24
20	1					25
10	1					26
13	1					27
54	2					28
22	1					29
13	1					30
34	1					31
14	1					32
140	1					33
17	1					34
45	1					35
		1				36
		1				37
25	1					38
140	1					39
4203	43	2				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
						2
6	1					3
7	1					4
9	1					5
8	1					6
		1				7
4233	47	3				8
						9
						10
20	1					11
14	1					12
14	1					13
11	1					14
10	3					15
10	1					16
94	2					17
28	2					18
10	1					19
10	1					20
39	2					21
10	1					22
10	1					23
14	1					24
10	3					25
37	1					26
37	1					27
37	1					28
20	2					29
14	1					30
11	1					31
14	1					32
14	1					33
14	1					34
14	1					35
12	1					36
14	1					37
14	1					38
22	1					39
22	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)	
12	1					1
12	3					2
10	3					3
10	1					4
10	1					5
28	2					6
10	1					7
10	1					8
84	2					9
		1				10
		1				11
		1				12
		1				13
24	2					14
20	2					15
12	1					16
842	58	4				17
						18
						19
842	58	4				20
4233	47	3				21
5075	105	9				22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 426 Line No.: 3 Column: a

Joint ownership, Otter Tail Power Company, 53.9%; Northwestern Public Service Company, 23.4%; Montana-Dakota Utilities Company, 22.7%. Expenses are shared on ownership percent basis. Accounts affected are regular accounts applicable to substations. None of the owners are associated companies.

Columns C, D, and E are reported in KVA.

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is \$250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	Non-power Goods or Services Provided by Affiliated			
2	Construction work in progress	Otter Tail Corporation	107	70,448
3	Expenditures for certain civic, political & relat	Otter Tail Corporation	426.4	17,273
4	Dividends declared - common stock	Otter Tail Corporation	438	40,456,413
5	Corporate allocated A&G expense	Otter Tail Corporation	See Note	10,670,134
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Non-power Goods or Services Provided for Affiliate			
21	Printing, design & mailing services	Otter Tail Corporation	417	17,432
22	Other deductions	Otter Tail Corporation	426.5	484,421
23				
24	Printing, design & mailing services	BTD Manufacturing	417	11,193
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
1	Non-power Goods or Services Provided by Affiliated			
2				

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)
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Non-power Goods or Services Provided for Affiliate			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
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38				
39				
40				
41				
42				

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 429 Line No.: 5 Column: a

Corporate allocated A&G expenses are allocated in accordance with Otter Tail Corporation's Corporate Cost Allocation Manual as approved by the Minnesota Public Utilities Commission, the North Dakota Public Service Commission, and the South Dakota Public Utilities Commission.

Schedule Page: 429 Line No.: 5 Column: c

The following accounts were charged:

500	\$	5,804
501		(1,852)
506		9,884
557		202
588		1,337
908		4,978
912		7,350
920		5,194,364
921		2,589,319
923		889,456
924		7,398
925		164,110
928		12,269
930.1		9,163
930.2		1,156,287
931		184,814
935		435,251

Total	\$	10,670,134

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