

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-19-188 Filed 05/17/2019 Pages: 231  
2018 FERC FORM No. 1  
Otter Tail Power Company

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

Otter Tail Power Company

**Year/Period of Report**

**End of** 2018/Q4

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

### GENERAL INFORMATION

#### I. Purpose

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

#### II. Who Must Submit

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

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

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

#### III. What and Where to Submit

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

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

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

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

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

The CPA Certification Statement should:

- a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and
- b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

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

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

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

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

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

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

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

#### **IV. When to Submit:**

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

- a) FERC Form 1 for each year ending December 31 must be filed by April 18<sup>th</sup> of the following year (18 CFR § 141.1), and
- b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

**V. Where to Send Comments on Public Reporting Burden.**

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 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>2018/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 Janelle Johnson		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) 739-8758	09 This Report Is (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		10 Date of Report (Mo, Da, Yr) 12/31/2018

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 Todd Wahlund	03 Signature  Todd Wahlund	04 Date Signed (Mo, Da, Yr) 04/16/2019
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	
25	Unrecovered Plant and Regulatory Study Costs	230	Not Applicable
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) 12/31/2018	Year/Period of Report End of 2018/Q4
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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) 12/31/2018	Year/Period of Report End of <u>2018/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.

**Janelle Johnson, 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> 12/31/2018	Year/Period of Report End of <u>2018/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	377,000
2			
3	President, Utility	Timothy J. Rogelstad	370,000
4			
5	Vice President, Customer Service	Mark H. Helland	198,661
6			
7	Chief Financial Officer [1]	George D. Bell	107,680
8			
9	Chief Financial Officer [2]	Todd R. Wahlund	155,336
10			
11	Vice President, Regulatory Affairs	Bruce G. Gerhardson	185,695
12			
13	General Counsel & Vice President, Legal Affairs * **	Jennifer O. Smestad	189,000
14			
15	Vice President, Asset Management	JoAnn M. Thompson	179,983
16			
17	Vice President, Energy Supply	Bradley E. Tollerson	209,444
18			
19	Vice President, Public Relations [3]	Cris M. Oehler	86,035
20			
21	Vice President, Information Technology * **	Don L. Redden	146,454
22			
23			
24			
25	Treasurer * **	Kevin G. Moug	261,960
26			
27	Assistant Treasurer [1] * **	Todd R. Wahlund	45,824
28			
29	Assistant Treasurer [2] * **	Andrew C. Miller	59,000
30			
31			
32			
33			
34	* This individual is an employee of		
35	Otter Tail Corporation.		
36	** Portion of salary allocated to the Utility.		
37			
38	[1] Removed effective 05/1/18		
39	[2] Effective 05/01/18		
40	[3] Removed effective 4/13/18		
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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)  
12/31/2018

Year/Period of Report  
End of 2018/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	Charles S. MacFarlane, Director, and CEO, Utility	Fergus Falls, Minnesota
3		
4	Kevin Moug, Director, Treasurer	Fargo, North Dakota
5		
6	Timothy J. Rogelstad, Director, President, Utility	Fergus Falls, Minnesota
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8	John Abbott, Director	Fargo, North Dakota
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10	Jennifer O. Smestad, Director, Secretary	Fergus Falls, Minnesota
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**INFORMATION ON FORMULA RATES**  
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?  Yes  No

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

Line No.	FERC Rate Schedule or Tariff Number	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	MISO FERC Electric Tariff	ER18-867

Name of Respondent  
Otter Tail Power Company

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

Date of Report  
(Mo, Da, Yr)  
12/31/2018

Year/Period of Report  
End of 2018/Q4

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

Does the respondent have formula rates?

Yes  
 No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	MISO FERC Electric Tariff	ER18-1982
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Name of Respondent  
Otter Tail Power Company

This Report Is:  
(1)  An Original  
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Date of Report  
(Mo, Da, Yr)  
12/31/2018

Year/Period of Report  
End of 2018/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	20170315-5207	03/15/2017	ER17-1234	Attachment O Annual Information	MSO FERC Electric Tariff
2	20180315-5167	03/15/2018	ER18-1118	Attachment O Annual Information	MSO 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 12/31/2018	Year/Period of Report End of <u>2018/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) 12/31/2018	Year/Period of Report 2018/Q4
Otter Tail Power Company			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

1. None.
2. None.
3. Quarter 1: None.

Quarter 2: In April, the FERC authorized three separate transmission asset-related transactions in each of EC18-44, EC18-7 and EC18-8. These transactions are authorized by the Commission in each of the orders in these dockets.

In EC18-44, pursuant to FPA Section 203, the FERC authorized the acquisition from East River Electric Power Cooperative, Inc. OTP's purchase of the Blair Substation Facilities pursuant to a June 10, 1983 Agreement between East River and Otter Tail. FERC authorized OTP to purchase those certain Blair Substation Assets but without seeking an approximately \$60,000 Acquisition Adjustment in OTP's FERC- Jurisdictional rates. The actual acquisition of those Blair Substation assets by OTP will not close until after all necessary regulatory approvals are received. Other FERC filings related to OTP's acquisition and eventual anticipated operation of the Blair Substation assets include the EREC-MISO-SPP-OTP interconnection agreement and the Letter Agreement between OTP and WAPA memorializing certain rights and obligations at the Blair Substation post-transfer of ownership, both filed on July 6, 2018 in FERC Docket Nos. ER18-1969 and ER18-1974, respectively. Action on both dockets pending.

FERC Section 203 Order was issued April 5, 2018. The related asset transfer petition for the Blair Substation Assets before the Minnesota Public Utilities Commission, MPUC Docket No. E017/PA-18-40, was approved by the Minnesota Commission by its "Order Approving Petition" issued June 13, 2018.

In EC18-7, the FERC authorized the transfer ownership pursuant to FPA Section 203 of certain transmission facilities associated with the Big Stone Plant for Otter Tail Power Company and Montana-Dakota Utilities Co. Those prior completed transactions were executed so that Big Stone's co- owners (Otter Tail Power Company, NorthWestern Corporation and Montana-Dakota Utilities Co. (MDU)) would hold shares of such facilities in proportion to the costs incurred by each public utility in constructing the Big Stone Plant and related Transmission Facilities. A compliance filing with proposed accounting entries was directed. Those proposed entities were filed with FERC on May 11, 2018 followed by revised entries based on additional FERC accounting staff input that were filed on July 10, 2018 (FERC Docket No. AC18-130, final action pending).

In EC18-8, the FERC authorized a completed transaction of a Shared Ownership Transfer pursuant to FPA Section 203 concerning certain transmission line facilities constructed by Northern Municipal Power Agency (NMPA) and whereby Otter Tail, Montana-Dakota Utilities Co. (MDU), NorthWestern Corporation, and NMPA share in the ownership of 10.69 miles of 345 kilovolt (kV) transmission line facilities related to Coyote Station. Parties shared in both the ownership and construction of the Transmission Facilities; FERC's Section 203 authorization approved transfers of shared ownership percentages. A compliance filing with purposed accounting entities was directed. Those proposed entities were filed with FERC on May 11, 2018, followed by revised entries based on additional FERC accounting staff input that were filed on July 10, 2018 (FERC Docket No. AC18-131, action pending).

FERC Section 203 Order issued April 11, 2018.

Quarter 3: No new applicable asset-related transactions; however, the five filings noted as "pending at FERC" in Q2 connected to earlier asset-related approvals were acted on by FERC in Q3.

In ER18-1969, on August 28, 2018, FERC accepted the First Revised Interconnection Agreement (T-T) between Otter Tail and East River as to the Southwest Power Pool (SPP) as part of the consummation and closing of the purchase of certain facilities in the F.L. Blair substation (approved in Q2 - April 15, 2018 - in FERC Docket No. EC18-44), effective Sept. 17, 2018.

In ER18-1970, on August 28, 2018, FERC accepted the First Revised Interconnection Agreement (T-T) between Otter Tail and East River as to the MISO as part of the consummation and closing of the purchase of certain facilities in the F.L. Blair substation (approved in Q2 - April 15, 2018 - in FERC Docket No. EC18-44), effective Sept. 17, 2018.

In ER18-1974, on August 30, 2018, FERC accepted a letter agreement between Otter Tail and Western Area

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) 12/31/2018	Year/Period of Report 2018/Q4
Otter Tail Power Company			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

Power Administration (WAPA) related to the consummation and closing of the purchase of certain facilities in the F.L. Blair substation (approved in Q2 - April 15, 2018 - in FERC Docket No. EC18-44), effective Sept. 17, 2018.

FERC approved the Otter Tail accounting entries that were noted as pending at FERC in the Q2 Report: FERC Docket No. AC18-130 (approved Aug. 28, 2018) and FERC Docket No. AC18-131 (approved Aug. 21, 2018)

Quarter 4: Otter Tail has filed and supplemented its compliance filing for the Otter Tail accounting entries that were required to accompany the Blair Substation purchase (FERC Docket EC18-44). FERC has assigned an accounting docket for its review of those proposed final entries, FERC Docket No. AC19-31. This matter is pending.

4. None.
5. None.
6. See Footnote 8 in Notes to Financial Statements. Minnesota Public Utilities Commission authorization given under Docket No. E-017/S-18-313 dated October 18, 2018
7. None.
8. The average annual increase for full-time nonunion employees was 2.995% effective April 1, 2018. Local Union 1570 received an average increase of 3.2% effective September 1, 2018. Local Unions 203, 239, 524, and 949 received a 3% increase effective November 1, 2018.
9. See Footnote 7 in Notes to Financial Statements.
10. Otter Tail Power Company is a subsidiary of Otter Tail Corporation.
11. (Reserved.)
12. None.
13. George D. Bell, Chief Financial Officer, removed effective May 1, 2018. Cris M. Oehler, Vice President, Public Relations, removed effective April 13<sup>th</sup>, 2018. Todd R. Wahlund, Assistant Treasurer, removed effective May 1, 2018. Todd R. Wahlund, appointed Chief Financial Officer, effective May 1, 2018. Andrew C. Miller appointed Assistant Treasurer, effective May 1, 2018.
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)
<b>1</b>	<b>UTILITY PLANT</b>			
2	Utility Plant (101-106, 114)	200-201	2,020,152,274	1,981,018,120
3	Construction Work in Progress (107)	200-201	170,614,396	132,556,715
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		2,190,766,670	2,113,574,835
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	782,870,571	745,531,210
6	Net Utility Plant (Enter Total of line 4 less 5)		1,407,896,099	1,368,043,625
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)		1,407,896,099	1,368,043,625
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
<b>17</b>	<b>OTHER PROPERTY AND INVESTMENTS</b>			
18	Nonutility Property (121)		660,311	579,911
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)		59,416	68,656
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		1,599,083	1,369,506
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)		2,318,810	2,018,073
<b>33</b>	<b>CURRENT AND ACCRUED ASSETS</b>			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		2,300	9,800
36	Special Deposits (132-134)		910,572	6,842,190
37	Working Fund (135)		12,467	12,462
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		18,824,873	18,861,634
41	Other Accounts Receivable (143)		9,015,298	7,125,495
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,081,142	859,149
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		9,299	7,374
45	Fuel Stock (151)	227	8,298,406	8,894,145
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	21,457,154	19,244,188
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	2,497	15,876

**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)		1,426,804	1,276,704
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)		23,592,861	22,426,606
62	Miscellaneous Current and Accrued Assets (174)		0	0
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)		82,471,389	83,857,325
68	<b>DEFERRED DEBITS</b>			
69	Unamortized Debt Expenses (181)		2,519,004	2,461,734
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	2,070,587	2,827,910
72	Other Regulatory Assets (182.3)	232	148,465,190	148,085,267
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)		365,778	267,828
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	173,102	60,876
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)		959,679	1,214,022
82	Accumulated Deferred Income Taxes (190)	234	98,531,568	103,691,997
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		253,084,908	258,609,634
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		1,745,771,206	1,712,528,657

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) 12/31/2018	2018/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, 2017	1,276,704
January 31, 2018	2,619,991
February 28, 2018	2,356,854
March 31, 2018	2,112,282
April 30, 2018	3,385,907
May 31, 2018	3,107,341
June 30, 2018	2,681,534
July 31, 2018	2,498,070
August 31, 2018	2,723,359
September 30, 2018	2,306,867
October 31, 2018	1,882,921
November 30, 2018	1,583,974
December 31, 2018	1,426,804
13-month average for rate-making	2,304,816

**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	401,988,966	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	190,724,111	178,800,320
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)	-1,640,844	-1,961,581
16	Total Proprietary Capital (lines 2 through 15)		591,072,733	553,828,205
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	512,000,000	412,000,000
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)		512,000,000	412,000,000
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)		613,034	618,804
29	Accumulated Provision for Pensions and Benefits (228.3)		148,088,024	155,936,999
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		1,576,474	0
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)		9,117,341	8,719,408
35	Total Other Noncurrent Liabilities (lines 26 through 34)		159,394,873	165,275,211
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		9,383,840	112,370,691
38	Accounts Payable (232)		49,465,050	49,338,850
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		1,876,513	2,066,743
41	Customer Deposits (235)		1,079,837	1,071,755
42	Taxes Accrued (236)	262-263	19,042,381	14,109,924
43	Interest Accrued (237)		7,862,199	6,208,534
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)		1,369,904	1,352,088
48	Miscellaneous Current and Accrued Liabilities (242)		13,600,020	4,568,417
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)		103,679,744	191,087,002
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	19,973,658	21,378,750
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	2,079,365	9,140,505
60	Other Regulatory Liabilities (254)	278	143,827,944	153,703,088
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	6,413,615	4,887,290
63	Accum. Deferred Income Taxes-Other Property (282)		189,766,063	186,474,995
64	Accum. Deferred Income Taxes-Other (283)		17,563,211	14,753,611
65	Total Deferred Credits (lines 56 through 64)		379,623,856	390,338,239
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		1,745,771,206	1,712,528,657

**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	445,935,618	430,559,311		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	261,373,507	246,677,605		
5	Maintenance Expenses (402)	320-323	31,502,109	28,046,187		
6	Depreciation Expense (403)	336-337	51,993,115	49,827,070		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	119,876	119,876		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	2,060,999	1,609,138		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		853,401	1,004,202		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		461,168	949,660		
13	(Less) Regulatory Credits (407.4)		1,248,654	1,625,731		
14	Taxes Other Than Income Taxes (408.1)	262-263	15,577,084	15,045,286		
15	Income Taxes - Federal (409.1)	262-263	2,240,170	-213,688		
16	- Other (409.1)	262-263	523,194	706,552		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	13,228,128	18,189,846		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	9,642,474	1,531,485		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,405,092	-1,470,564		
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	16		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		397,933	378,404		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		368,034,448	357,712,342		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117, line 27		77,901,170	72,846,969		

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	
						1
445,935,618	430,559,311					2
						3
261,373,507	246,677,605					4
31,502,109	28,046,187					5
51,993,115	49,827,070					6
119,876	119,876					7
2,060,999	1,609,138					8
						9
853,401	1,004,202					10
						11
461,168	949,660					12
1,248,654	1,625,731					13
15,577,084	15,045,286					14
2,240,170	-213,688					15
523,194	706,552					16
13,228,128	18,189,846					17
9,642,474	1,531,485					18
-1,405,092	-1,470,564					19
						20
						21
16	16					22
						23
397,933	378,404					24
368,034,448	357,712,342					25
77,901,170	72,846,969					26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL		Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
			Current Year (c)	Previous Year (d)		
27	Net Utility Operating Income (Carried forward from page 114)		77,901,170	72,846,969		
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)		569,568	667,131		
34	(Less) Expenses of Nonutility Operations (417.1)		359,180	431,062		
35	Nonoperating Rental Income (418)		54,150	56,826		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		145,707	155,423		
38	Allowance for Other Funds Used During Construction (419.1)		2,194,111	986,150		
39	Miscellaneous Nonoperating Income (421)		3,277,090	2,952,392		
40	Gain on Disposition of Property (421.1)		3,494	30,101		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		5,884,940	4,416,961		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		1,221			
44	Miscellaneous Amortization (425)		88,420			
45	Donations (426.1)		1,452,011	454,232		
46	Life Insurance (426.2)					
47	Penalties (426.3)					
48	Exp. for Certain Civic, Political & Related Activities (426.4)		280,043	242,641		
49	Other Deductions (426.5)		420,343	446,449		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		2,242,038	1,143,322		
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	906,575	380,146		
54	Income Taxes-Other (409.2)	262-263	294,044	75,637		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	723,078	1,099,778		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	1,183,121	223,654		
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)		748,424	1,339,755		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		2,894,478	1,933,884		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		25,620,094	23,222,858		
63	Amort. of Debt Disc. and Expense (428)		539,477	379,982		
64	Amortization of Loss on Reaquired Debt (428.1)		254,343	325,098		
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)		1,156,622	2,147,103		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		1,205,524	740,730		
70	Net Interest Charges (Total of lines 62 thru 69)		26,365,012	25,334,311		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		54,430,636	49,446,542		
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)		54,430,636	49,446,542		

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		178,138,711	169,188,039
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)		54,430,636	49,446,542
17	Appropriations of Retained Earnings (Acct. 436)			
18	Excess Hydro Licensing Amortization		-32,628	( 39,457)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-32,628	( 39,457)
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			-42,506,846	( 40,456,413)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-42,506,846	( 40,456,413)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		190,029,873	178,138,711
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39	Amortization Reserve, Federal (Account 215.1)		694,238	661,609
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)		694,238	661,609
	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)		694,238	661,609
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		190,724,111	178,800,320
	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)	54,430,636	49,446,542
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	52,112,993	49,946,947
5	Amortization	2,600,475	1,989,120
6	Vehicle Depreciation allocated to various operating accounts	1,922,330	1,845,271
7			
8	Deferred Income Taxes (Net)	12,787,422	16,609,634
9	Investment Tax Credit Adjustment (Net)	-1,405,092	-1,470,564
10	Net (Increase) Decrease in Receivables	-1,632,974	323,548
11	Net (Increase) Decrease in Inventory	-1,617,227	514,972
12	Net (Increase) Decrease in Allowances Inventory	13,379	15,509
13	Net Increase (Decrease) in Payables and Accrued Expenses	16,438,199	-6,471,336
14	Net (Increase) Decrease in Other Regulatory Assets	377,400	-859,367
15	Net Increase (Decrease) in Other Regulatory Liabilities	-9,875,144	299,764
16	(Less) Allowance for Other Funds Used During Construction	2,194,111	986,150
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other: (Increase)Decrease in Noncurrent Assets & Deferred Debits	-176,170	-269,683
19	Other: Increase(Decrease) in Noncurrent Liabilities & Deferred Credi	-12,620,741	12,810,969
20	Other: (Increase)Decrease in Other Current Assets	-1,316,355	-914,131
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	109,845,020	122,831,045
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-95,948,794	-114,151,636
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-80,400	300,000
30	(Less) Allowance for Other Funds Used During Construction	-2,194,111	-986,150
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-93,835,083	-112,865,486
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		
50	Net (Increase ) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses	-373,135	11,880
53	Other: (increase) decrease in funds on deposit with trustee	5,931,618	-3,633,830
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-88,276,600	-116,487,436
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	-596,747	-222,279
65			
66	Net Increase in Short-Term Debt (c)		69,487,413
67	Other: Change in Checks Written in Excess of Cash	-485,471	-2,152,313
68	Other: Proceeds from Capital Infusions	25,000,000	
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	23,917,782	67,112,821
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	100,000,000	-33,000,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)	-102,986,851	
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-42,506,846	-40,456,413
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-21,575,915	-6,343,592
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-7,495	17
87			
88	Cash and Cash Equivalents at Beginning of Period	22,262	22,246
89			
90	Cash and Cash Equivalents at End of period	14,767	22,263

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) 12/31/2018	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

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

Amortization on 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 on reacquired debt.

**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**

Debit 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 12/31/2018	Year/Period of Report End of <u>2018/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.

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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 as considered cash equivalents.

Reconciliation	2018	2017
Cash - Account 131 (line 35, Page 110)	\$ 2,300	\$ 9,800
Working Fund - Account 135 (Line 37, Page 110)	12,467	12,462
Cash Equivalents	0	0
	\$ 14,767	\$ 22,262

Otter Tail Power Company  
Notes to Financial Statements  
For the years ended December 31, 2018 and 2017

## 1. Summary of Significant Accounting Policies

### Organization and Operations

Otter Tail Power Company (OTP) is a wholly owned subsidiary of Otter Tail Corporation, both Minnesota corporations. 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, 2018, OTP served 132,448 customers. Although there are relatively few large customers, sales to commercial and industrial customers are significant. One customer accounted for 11% of the 2018 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>	2018	2017
Accounts Receivable	\$ 7	\$ 7
Accounts Payable	1,877	2,067
Operating Revenues	57	31
Other Operation and Maintenance Expenses	11,266	10,725

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.

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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.
- 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 FERC presentation and reported as operating income and expenses for the GAAP presentation.
- Revenue is classified in the Income Statement as Operating Revenue based on FERC account, while GAAP presentation reflects revenue as either revenues from contract with customers or alternative revenue programs.
- A portion of the non-service benefit costs are capitalized and included is rate base additions for rate recovery for regulatory treatment, while GAAP presentation reflects these costs as non-operating expenses.

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 \$1,206,000 in 2018 and \$741,000 in 2017. 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 2.76% in 2018 and 2.74% in 2017. 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.

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#### 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 OTP's ownership percentages and amounts included in OTP's December 31, 2018 and 2017 balance sheets for OTP's share of jointly owned assets in each of these jointly owned facilities:

Jointly Owned Facilities (dollars in thousands)	OTP		Construction Work in Progress	Accumulated Depreciation	Net Plant
	Ownership Percentage	Electric Plant in Service			
<b>December 31, 2018</b>					
Big Stone Plant	53.9%	\$ 336,051	\$ 361	\$ (92,007)	\$ 244,405
Coyote Station	35.0%	177,713	2,588	(100,997)	79,304
Fargo–Monticello 345 kV line	14.2%	78,184	--	(5,891)	72,293
Brookings–Southeast Twin Cities 345 kV line	4.8%	26,281	--	(1,713)	24,568
Bemidji–Grand Rapids 230 kV line	14.8%	16,331	--	(2,091)	14,240
Big Stone South–Brookings 345 kV line	50.0%	53,235	(150)	(1,264)	51,821
Big Stone South–Ellendale 345 kV line <sup>1</sup>	50.0%	--	106,490	--	106,490
<b>December 31, 2017</b>					
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	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	50.0%	53,225	--	(434)	52,791
Big Stone South–Ellendale 345 kV line <sup>1</sup>	50.0%	--	89,980	--	89,980

<sup>1</sup>MISO 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 OTP's 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

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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, 2018 could be as high as \$53.9 million, OTP's 35% share of unrecovered costs.

#### 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 12 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 \$1.5 million and \$2.5 million of deferred taxes associated with net operating losses that had been utilized by the consolidated group as of December 31, 2018 and 2017, 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 President signed into law Pub L. 115-97 which is referred to as the Tax Cuts and Jobs Act. The TCJA contained many provisions, most notably a reduction of the Federal corporate income tax rate. Following almost immediately, all jurisdictions opened dockets to investigate the impact customers rates. In December 2017, OTP remeasured its deferred tax assets and liabilities to the new Federal corporate income tax rate of 21%. The result of this remeasurement was a reduction in the net deferred tax liability of approximately \$109 million. Based on our estimate of the amount of excess deferred income taxes that would be used to reduce future customer rates, we recorded an increase in regulatory liabilities of approximately \$147 million.

The accounts that increased and (decreased) in the 2017 remeasurement of deferred income taxes are reflected below (in millions):

<u>Jurisdiction</u>	<u>254</u>	<u>190</u>	<u>281</u>	<u>282</u>	<u>283</u>
FERC	\$6.7	(\$1.0)	(\$0.1)	(\$7.1)	(\$0.5)
Minnesota	\$74.0	(\$10.8)	(\$1.1)	(\$77.8)	(\$5.9)
North Dakota	\$54.6	(\$7.0)	(\$0.8)	(\$56.5)	(\$4.3)
South Dakota	\$11.6	(\$1.7)	(\$0.2)	(\$12.2)	(\$0.9)
<b>Total</b>	<b>\$146.9</b>	<b>(\$20.5)</b>	<b>(\$2.2)</b>	<b>(\$153.6)</b>	<b>(\$11.6)</b>

Small adjustments were made to these balances from year-end 2017 related to finalization of the company's tax return accounting during 2018.

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All state jurisdictions opened dockets (Minnesota: E, G-999/CI-17-895; North Dakota: PU-17-490; South Dakota: GE17-3) regarding how customer rates should be reduced for excess deferred income taxes. OTP has received guidance as a result of these dockets and will reduce our regulatory liability related to excess deferred income taxes against account 411.1. The estimated amortization, period, account, and the category of such deferred taxes is reflected below (in millions):

<u>Jurisdiction</u>	<u>2018</u>	<u>Amortization Period</u>
<i>411.1</i>		
FERC - protected	\$0.14	Estimated 30 years under ARAM
Minnesota – protected	\$1.79	Estimated 30 years under ARAM
North Dakota – protected	\$1.31	Estimated 30 years under ARAM
South Dakota – protected	\$0.22	Estimated 30 years under ARAM
FERC - unprotected	\$0.01	5 years straight line (est.)
Minnesota – unprotected	\$0.18	10 years straight line
North Dakota – unprotected	\$0.09	5 years straight line
South Dakota – unprotected	\$0.01	4 years straight line

*In the table above, ARAM refers to the average rate assumption method.*

#### 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.

#### 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.

#### 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.

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#### 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:

<i>(in thousands)</i>	2018	2017
Cost Method – Economic Development Loan Pools	\$ 34	\$ 45
Equity Method – Partnership	26	24
Total Investments	\$ 60	\$ 69

#### 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,	
	2018	2017
Noncash Investing Activities:		
Transactions Related to Capital Additions not Settled in Cash	\$ 13,060	\$ 13,433
<i>(in thousands)</i>	2018	2017
Cash Paid During the Year for:		
Interest (net of amount capitalized)	\$ 23,954	\$ 25,366
Income Tax (Refunds) Payments	\$ (1,166)	\$ 2,348

#### New Accounting Standards Adopted

ASU 2014-09 In May 2014 the Financial Accounting Standards Board (FASB) issued a major update to the ASC, ASU 2014-09, *Revenue from Contracts with Customers* (Topic 606) (ASC 606). OTP adopted the updates in ASC 606 effective January 1, 2018 on a modified retrospective basis but did not record a cumulative effect adjustment to retained earnings on application of the updates because the adoption of the updates in ASC 606 had no material impact on the timing of revenue recognition for OTP.

The amendments in ASU 2014-09 change the presentation of revenue in the Income Statement for GAAP purposes but have no impact on FERC presentation and timing of revenue recognition.

ASU 2017-07—In March 2017 the FASB issued ASU 2017-07 with the intent of improving the presentation of net periodic pension cost and net periodic postretirement benefit cost. ASC Topic 715, *Compensation—Retirement Benefits* (ASC 715). The amendments in ASU 2017-07 require for GAAP presentation 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 deviate significantly from current prescribed ratemaking and regulatory accounting treatment of postretirement benefit costs applicable to OTP, 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 the components of net periodic pension costs as recoverable operating expenses.

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### New Accounting Standards Pending Adoption

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 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. OTP has developed a list of all its current leases outstanding. OTP has determined areas where the amendments in ASU 2016-02 are applicable to its business, evaluated transition options and determined the practical expedients it will elect on implementation. OTP will apply the amendments in ASU 2016-02 to its financial statements in the first quarter of 2019. Other than first-time recognition of these types of operating leases on OTP's balance sheet, the implementation is not expected to have a significant impact on OTP's financial statements. See note 6 for further information on leases and the OTP's elections for applying the new standard and the expected impacts on adoption.

### Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2018 up to March 7, 2019, the date the Company's U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 16, 2019. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

OTP accrued refund liabilities for the time periods when revenues were collected under rates set to recover higher levels of federal income taxes than OTP incurs under the lower federal tax rates in the TCJA. Through February 2019, OTP has accrued a refund liability for the South Dakota jurisdictional impact of the tax rate change of \$1.0 million. On March 31, 2019, OTP reversed this accrual based on the outcome of the South Dakota Rate Case Settlement.

## **2. Rate and Regulatory Matters**

Below are descriptions of OTP's major capital expenditure projects that have had, or are expected to have, a significant impact on OTP's revenue 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 2018 and 2017.

### Major Capital Expenditure Projects

Merricourt Project—On November 16, 2016 OTP entered into an Asset Purchase Agreement (the Purchase Agreement) with EDF Renewable Development, Inc. and certain of its affiliated companies (EDF) to purchase and assume the development assets and certain specified liabilities associated with a 150-megawatt (MW) wind farm in southeastern North Dakota (the Merricourt Project) for a purchase price of approximately \$34.7 million, subject to adjustments for interconnection costs. The Purchase Agreement will close on satisfaction of various closing conditions (including regulatory approvals). Also on November 16, 2016, OTP entered into a Turnkey Engineering, Procurement and Construction Services Agreement with EDF pursuant to which EDF will develop, design, procure, construct, interconnect, test and commission the wind farm with a targeted completion date in 2020 for consideration of approximately \$200.5 million, subject to certain adjustments, payable following the closing of the Purchase Agreement in installments in connection with certain project construction milestones. Depending on the timing of MISO interconnection approval, construction of the Merricourt Project is currently anticipated to begin in mid-2019. The agreements contain customary representations, warranties, covenants and indemnities for this type of transaction. As of December 31, 2018, OTP had capitalized approximately \$4.9 million in development costs associated with the Merricourt Project. A final order for an Advance Determination of Prudence (ADP), subject to qualifications and compliance obligations, and a Certificate of Public Convenience and Necessity were issued by the NDPSC on

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November 3, 2017. On October 26, 2017 the MPUC approved the facility under the Renewable Energy Standard making the Merricourt Project eligible for cost recovery under the Minnesota Renewable Resource Recovery rider, subject to qualifications and reporting obligations.

Astoria Station—OTP is moving forward with plans for the development, construction and ownership of this 250-MW simple-cycle natural gas-fired combustion turbine generation facility near Astoria, South Dakota as part of its plan to reliably meet customers' electric needs, replace expiring capacity purchase agreements and prepare for the planned retirement of its Hoot Lake Plant in 2021. As of December 31, 2018, OTP had capitalized approximately \$8.3 million in development and other costs associated with Astoria Station. On August 3, 2018 the SDPUC issued an order granting a site permit for Astoria Station. A final order granting ADP for Astoria Station was issued by the NDPSC on November 3, 2017, subject to certain qualifications and compliance obligations. The interconnection agreement for Astoria Station was executed by MISO in December 2018 and accepted by the FERC in January 2019. In a September 26, 2018 hearing the NDPSC approved an overall annual revenue increase for OTP and established a Generation Cost Recovery rider for future recovery of costs incurred for Astoria Station.

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., and the parties will have equal ownership interest in the transmission line portion of the project. The 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 MISO 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 the line was energized on February 6, 2019. OTP's capitalized costs on this project as of December 31, 2018 were approximately \$106 million, which includes assets that are 100% owned by OTP.

Big Stone South–Brookings 345-kV MVP—OTP invested approximately \$73 million, which includes assets that are 100% owned by OTP, and has a 50.0% ownership interest in the jointly-owned assets of this 70-mile transmission line energized in 2017.

Recovery of OTP's major transmission investments is through the MISO Tariff (several as MVPs) and, currently, Minnesota, North Dakota and South Dakota base rates and 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 Air Quality Control System (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

General Rates—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 (ROE) decreased from 10.74% to 9.41%.

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 MVPs will be included in the Minnesota TCR rider and jurisdictionally allocated to OTP's Minnesota customers (see discussion under Minnesota Transmission Cost Recovery Rider below), and (2) approval of OTP's proposal to transition rate base, expenses and revenues from ECR and TCR riders to base rate recovery, which occurred when final rates were implemented on November 1, 2017. 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.

OTP accrued interim and rider rate refunds until final rates became effective. 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. In addition to the interim rate refund, OTP refunded the difference between (1) amounts collected under its Minnesota ECR and TCR riders based on the 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. 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,

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respectively. These amounts were refunded to Minnesota customers over a 12-month period beginning in November 2017 through reductions in the Minnesota ECR and TCR rider rates. The TCR rider rate is provisional and subject to revision under a separate docket.

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 (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 included as 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 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. The financial incentive is also limited to 40% of 2017 MNCIP spending, 35% of 2018 spending and 30% of 2019 spending. The new model reduces the MNCIP financial incentive by approximately 50% compared to the previous incentive mechanism.

Based on results from the 2016 MNCIP program year, OTP recognized MNCIP financial incentives of \$5.1 million in 2016, which included a \$0.1 million true-up of 2015 financial incentives earned. The 2016 program resulted in an approximate 18% increase in energy savings compared to 2015 program results. On March 31, 2017 OTP requested approval for recovery of its 2016 MNCIP program costs not included in base rates, \$5.0 million in performance incentives and an update to the MNCIP surcharge from the MPUC. On September 15, 2017 the MPUC issued an order approving OTP's request with an effective date of October 1, 2017.

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 a decrease in energy savings compared to 2016 program results of approximately 10%. OTP requested approval for recovery of its 2017 MNCIP program costs not included in base rates on March 30, 2018. The request included a \$2.6 million financial incentive and an update to the MNCIP surcharge from the MPUC. On June 13, 2018 OTP increased its request for a financial incentive to \$2.9 million. On October 4, 2018, the MPUC issued an order approving OTP's request of \$2.9 million subject to further review by the MPUC to ensure no previous decisions conflict with the decision, with \$0.3 million subject to a possible subsequent refund.

Based on results from the 2018 MNCIP program year, OTP recognized \$3.0 million out of a potential \$3.15 million in financial incentives earned in 2018. OTP will request approval for recovery of its 2018 program costs not included in base rates, a \$3.15 million financial incentive and an update to its MNCIP surcharge from the MPUC by April 1, 2019.

Transmission Cost Recovery Rider—The Minnesota Public Utilities Act (the MPU Act) authorizes the MPUC to approve 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 that are 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 most recently completed general rate case or such other rate of return the MPUC determines is in the public interest. Additionally,

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following approval of a 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 MVPs 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 diverted 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 resulted in the projects being treated as retail investments for Minnesota retail ratemaking purposes. Because the FERC's revenue requirements and authorized returns vary from the MPUC revenue requirements and authorized returns for the project investments over the lives of the projects, the impact of this decision would 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 jurisdictionally allocate costs of the FERC MVP transmission projects in the TCR rider.

On June 11, 2018 the Minnesota Court of Appeals reversed the MPUC's order related to the inclusion of Minnesota's jurisdictional share of OTP's investment in the Big Stone South–Brookings and Big Stone South–Ellendale MVPs and all revenues received from other utilities under MISO's tariffed rates as a credit in OTP Minnesota TCR revenue requirement calculations. On July 11, 2018 the MPUC filed a petition for review of the MVP decision to the Minnesota Supreme Court, which granted review of the Minnesota Court of Appeals decision. A decision by the Minnesota Supreme Court is expected in either second or third quarter 2019.

On November 30, 2018 OTP filed its annual update and supplemental filing to the Minnesota TCR rider. In this filing two scenarios were submitted based on whether the Minnesota Supreme Court affirms the original decision by the Minnesota Court of Appeals to exclude the MVP projects from the TCR rider or overturns the Minnesota Court of Appeals decision and includes the two MVP projects in the TCR rider. In both situations the rates are proposed to be effective June 1, 2019 if a decision is made in late first quarter or early second quarter 2019. If the decision is made later than second quarter of 2019, it is likely the MPUC will delay its decision on the TCR rider update. The amount credited to Minnesota customers through the TCR through December 31, 2018 and subject to recovery if the Minnesota Court of Appeals decision is upheld, is approximately \$2.3 million.

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 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. Accordingly, in its 2018 annual update filing OTP requested, and the MPUC approved, setting the Minnesota ECR rider rate to zero effective December 1, 2018.

Reagent Costs and Emission Allowances—These costs were included in OTP's 2016 general rate case in Minnesota and were considered for recovery either through the Fuel Clause Adjustment (FCA) rider or base rates. In its 2016 general rate case order issued May 1, 2017 the MPUC denied OTP's request for recovery of test-year reagent costs and emission allowances in base fuel costs and through the FCA rider. Instead, the test-year costs are being recovered in base rates and variability of those costs in excess of amounts included in base rates will only be recovered to the extent actual kwh sales exceed forecasted kwh sales used to establish base 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%. The requested \$13.1 million increase was net of reductions in North Dakota RRA, TCR and ECR rider revenues that would have resulted from a lower allowed rate of return on equity and changes in allocation factors in the general rate case. In the request, OTP proposed an allowed return on rate base of 7.97% and an allowed rate of return on equity of 10.3%. 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. In response to the reduction in the federal corporate tax rate under the TCJA, the NDPSC issued an order on February 27, 2018 reducing OTP's annual revenue requirement for interim rates by \$4.5 million to \$8.3 million, effective March 1, 2018.

On March 23, 2018 OTP made a supplemental filing to its initial request for a rate review, reducing its request for an annual revenue

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increase from \$13.1 million to \$7.1 million, a 4.8% annual increase. The \$6.0 million decrease included \$4.8 million related to tax reform and \$1.2 million related to other updates.

In a September 26, 2018 hearing the NDPSC approved an overall annual revenue increase of \$4.6 million (3.1%) and a ROE of 9.77% on a 52.5% equity capital structure. This compares with OTP's March 2018 adjusted annual revenue increase request of \$7.1 million (4.8%) and a requested ROE of 10.3%. The NDPSC's approval does not require any rate base adjustments from OTP's original request and establishes a Generation Cost Recovery rider for future recovery of costs incurred for Astoria Station. The net revenue increase reflects a reduction in income tax recovery requirements related to the TCJA and decreases in rider revenue recovery requirements. Final rates were effective February 1, 2019, with refunds of excess revenues collected under interim rates applied to customers' April 2019 bills. OTP has accrued an interim rate refund of \$3.0 million as of December 31, 2018, which includes \$0.8 million in excess revenue collected for income taxes under interim rates in effect in January and February 2018.

OTP's previously approved general rate increase in North Dakota of \$3.6 million, or approximately 3.0%, was granted by the NDPSC in an order issued in November 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 RRA 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.

Effective in February 2019 with the implementation of general rates based on the results of OTP's 2017 general rate case, recovery of renewable resource costs previously being recovered through the North Dakota RRA rider transitioned to recovery in base rates.

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. Based on the order in the 2017 general rate case, only certain costs will remain subject to refund or recovery through this rider: Southwest Power Pool (SPP) costs and MISO Schedule 26 and 26A revenues and expenses and costs related to rider projects still under construction in the test year used in the 2017 general rate case. This rider will continue to be updated annually for new or modified electric transmission facilities and associated operating costs.

Environmental Cost Recovery Rider—OTP has an ECR rider in North Dakota. The ECR rider has provided for a return on investment at the level approved in OTP's preceding general rate case and for recovery of OTP's North Dakota share of environmental investments and costs approved for recovery under the rider. Prior to its 2017 general rate case reaching a final settlement and final rates going into effect on February 1, 2019, OTP's North Dakota jurisdictional share of the revenue requirements associated with its investment in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects were being recovered through the ECR rider. Effective February 1, 2019 these rate base investments are being recovered under general rates and the rider was zeroed out except for an overcollection balance that will be refunded to ratepayers through the rider.

#### South Dakota

General Rates—On April 20, 2018 OTP filed a request with the SDPUC to increase non-fuel rates in South Dakota by approximately \$3.3 million annually, or 10.1%, as the first step in a two-step request. Interim rates went into effect October 18, 2018. On February 5, 2019 SDPUC staff and OTP requested that the SDPUC issue a procedural schedule setting evidentiary hearings for March 26-28, 2019. The full effects of the TCJA on South Dakota revenue requirements will be addressed in the rate case and incorporated into final rates at the conclusion of that case. The second step in the request is an additional 1.7% increase to recover costs for the proposed Merricourt wind generation facility when the facility goes into service. On February 15, 2019 OTP reached a partial settlement with SDPUC staff which requires SDPUC approval.

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OTP's previously approved general rate increase in South Dakota of approximately \$643,000 or approximately 2.32% was granted by the SDPUC in an order issued in April 2011 and effective in June 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. OTP has a TCR rider in South Dakota. A supplemental filing to update the rider was made on January 29, 2018 to reflect updated costs and collections and incorporate the impact of the reduction in the federal corporate income tax rate under the TCJA. Effective October 18, 2018, with the implementation of interim rates under South Dakota general rate case proceedings, the TCR rate was decreased as a result of recovery of certain costs being shifted to recovery in interim rates and proposed for ongoing recoveries in final base rates at the end of the 2018 general rate case.

Environmental Cost Recovery Rider—OTP has an ECR rider in South Dakota. 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 South Dakota share of environmental investments and costs approved for recovery under the rider. Prior to interim rates going into effect on October 18, 2018 pending a final decision on OTP's South Dakota general rate increase request, OTP's South Dakota jurisdictional share of the revenue requirements associated with its investment in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects were being recovered through the ECR rider. With the initiation of interim rates, recovery of the costs previously being recovered under the ECR rider was transitioned to recovery under interim rates and the South Dakota ECR rider rate was reset to provide a refund to customers while interim rates are in effect.

Reagent Costs and Emission Allowances—The SDPUC has approved the recovery of reagent and emission allowance costs in OTP's South Dakota FCA rider.

#### 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:

Rate Rider ( <i>in thousands</i> )	2018	2017
<u>Minnesota</u>		
Conservation Improvement Program Costs and Incentives <sup>1</sup>	\$12,028	\$ 9,225
Renewable Resource Adjustment	3,067	(196)
Environmental Cost Recovery	(24)	8,148
Transmission Cost Recovery	(2,039)	2,973
<u>North Dakota</u>		
Renewable Resource Adjustment	8,529	7,620
Environmental Cost Recovery	7,318	9,782
Transmission Cost Recovery	7,016	8,729
<u>South Dakota</u>		
Environmental Cost Recovery	1,676	2,345
Transmission Cost Recovery	1,664	1,843
Conservation Improvement Program Costs and Incentives	628	598

<sup>1</sup>Includes MNCIP costs recovered in base rates.

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### Rate Rider Updates

The following table provides summary information on the status of updates since January 1, 2016 for the rate riders described above:

Rate Rider	R - Request Date A - Approval Date	Effective Date Requested or Approved	Annual Revenue (\$000s)	Rate
<b>Minnesota</b>				
Conservation Improvement Program				
2017 Incentive and Cost Recovery	A – October 4, 2018	November 1, 2018	\$10,283	\$0.00600/kwh
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
Transmission Cost Recovery				
2018 Annual Update–Scenario A	R – November 30, 2018	June 1, 2019	\$ 6,475	Various
–Scenario B			\$ 2,708	Various
2017 Rate Reset	A – October 30, 2017	November 1, 2017	\$ (3,311)	Various
2016 Annual Update	A – July 5, 2016	September 1, 2016	\$ 4,736	Various
Environmental Cost Recovery				
2018 Annual Update	A – November 29, 2018	December 1, 2018	\$ --	0% of base
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
Renewable Resource Adjustment				
2018 Annual Update	A – August 29, 2018	November 1, 2018	\$ 5,886	\$.00244/kwh
2017 Rate Reset	A – October 30, 2017	November 1, 2017	\$ 1,279	\$.00049/kwh
<b>North Dakota</b>				
Renewable Resource Adjustment				
2019 Annual Update	R – December 31, 2018	April 1, 2019	\$ (236)	-0.224% of base
2018 Rate Reset for effect of TCJA	A – February 27, 2018	March 1, 2018	\$ 9,650	7.493% of base
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
Transmission Cost Recovery				
2018 Supplemental Update	A – December 6, 2018	February 1, 2019	\$ 4,801	Various
2018 Rate Reset for effect of TCJA	A – February 27, 2018	March 1, 2018	\$ 7,469	Various
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
Environmental Cost Recovery				
2018 Update	A – December 19, 2018	February 1, 2019	\$ (378)	-0.310% of base
2018 Rate Reset for effect of TCJA	A – February 27, 2018	March 1, 2018	\$ 7,718	5.593% of base
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
<b>South Dakota</b>				
Transmission Cost Recovery				
2018 Interim Rate Reset	A – October 18, 2018	October 18, 2018	\$ 1,171	Various
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
Environmental Cost Recovery				
2018 Interim Rate Reset	A – October 18, 2018	October 18, 2018	\$ (189)	-\$0.00075/kwh
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

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## TCJA

The TCJA, passed in December 2017, reduced the federal corporate income tax rate from 35% to 21%, effective January 1, 2018. At the time of passage, all OTP's rates had been developed using a 35% tax rate. The MPUC, the NDPSC, the SDPUC and the FERC each initiated dockets or proceedings to begin working with utilities to assess the impact of the lower rates on electric rates, and to develop regulatory strategies to incorporate the tax change into future rates, if warranted.

The MPUC required regulated utilities providing service in Minnesota to make filings by February 15, 2018. On August 9, 2018 the MPUC determined the impacts of the TCJA as calculated, including amortization of excess accumulated deferred income taxes, should be refunded and rates should be adjusted going forward to account for the impacts of the TCJA. On December 5, 2018 the MPUC released its final order related to the TCJA docket which directs OTP to return to ratepayers, in a one-time refund, the TCJA-related savings accrued prior to the refund effective date. OTP must amortize its protected excess accumulated deferred income taxes (ADIT) as early as U.S. Internal Revenue Service provisions allow and amortize its unprotected excess ADIT over ten years. OTP was instructed to use its 2017 year-end ADIT balance to calculate its excess ADIT balance. The order also directs OTP to use these savings to reduce customers' base rates prospectively—allocating the savings to customers in proportion to the size of each customer's bill, or to each customer class in proportion to the class's size. OTP expects the rate change and refund to occur in the second quarter of 2019, pending MPUC approval of OTP's January 3, 2019 compliance filing.

As described above, OTP's current general rate cases in North Dakota and South Dakota reflect the ongoing impact of the TCJA in interim rates. OTP has accrued refund liabilities for the time periods when revenues were collected under rates set to recover higher levels of federal income taxes than OTP incurs under the lower federal tax rates in the TCJA. As of December 31, 2018, accrued refund liabilities related to the tax rate reduction were \$8.4 million in Minnesota, \$0.8 million in North Dakota for amounts collected reflecting the higher tax rates under interim rates in effect in January and February 2018, \$1.0 million in South Dakota billed prior to October 18, 2018, and \$0.2 million for FERC jurisdictional rates. As noted in subsequent events, OTP has reversed the accrual for refunds due to South Dakota TCJA as of March 2019.

As of March 15, 2018, the FERC granted the request for waiver from a group of MISO transmission operators (including OTP) to revise inputs to their projected net revenue requirements for the 2018 rate year to reflect recent tax law changes.

## FERC

Wholesale power sales and transmission rates are subject to the jurisdiction of the FERC under the Federal Power Act of 1935 (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 suspension period, subject to ultimate approval by the FERC.

MVPs—MVPs are designed to enable the MISO 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%. Several 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 went to 10.82% (a 10.32% base ROE plus the 0.5% RTO Adder) effective September 28, 2016.

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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, 2018.

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 U.S. 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 NETOs complaint. The motion is currently pending before the FERC.

On October 16, 2018 the FERC issued an order proposing a methodology for addressing the issues that were remanded to the FERC by the D.C. Circuit in April 2017. The FERC order established a paper hearing on how the methodology should apply to the proceedings pending before the FERC involving NETOs' ROE. In the order, the FERC selected a preliminary just and reasonable ROE for NETOs of 10.41%, exclusive of incentives, with a proposed cap on any pre-existing incentive-based total ROE at 13.08% and directed participants to submit supplemental briefs and additional written evidence regarding the proposed approaches to the Federal Power Act Section 206 inquiry and how to apply them to the NETO ROE complaints. On November 15, 2018, FERC issued an order establishing a paper hearing on whether and how a two-step ROE methodology developed for NETOs should apply to the ROE for MISO transmission owners. Initial briefs were due February 13, 2019 and reply briefs are due April 10, 2019.

OTP believes its estimated accrued MISO Tariff ROE refund liability of \$1.6 million as of December 31, 2018 related to the second MISO tariff ROE complaint is appropriate.

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### 3. Other 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, 2018	Remaining Recovery/Refund Period (months)
<b>Other Regulatory Assets:</b>		
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits <sup>1</sup>	\$124,779	see below
Conservation Improvement Program Costs and Incentives <sup>2</sup>	9,280	21
Accumulated ARO Accretion/Depreciation Adjustment <sup>1</sup>	7,169	asset lives
Deferred Income Taxes <sup>1</sup>	2,423	asset lives
Deferred Marked-to-Market Losses <sup>1</sup>	2,404	24
North Dakota Deferred Rate Case Expenses Subject to Recovery <sup>1</sup>	455	12
Minnesota Renewable Resource Recovery Rider Accrued Revenues <sup>2</sup>	452	12
Minnesota Transmission Cost Recovery Rider Accrued Revenues <sup>2</sup>	444	12
Minnesota Energy Intensive Trade Exposed Rider Accrued Revenues <sup>1</sup>	327	4
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up <sup>1</sup>	240	12
South Dakota Deferred Rate Case Expenses Subject to Recovery <sup>1</sup>	178	12
Minnesota SPP Transmission Cost Recovery Tracker <sup>1</sup>	176	see below
Minnesota Environmental Cost Recovery Rider Accrued Revenues <sup>2</sup>	121	12
North Dakota Environmental Cost Recovery Rider Accrued Revenues <sup>2</sup>	17	12
<b>Total Other Regulatory Assets</b>	<b>\$ 148,465</b>	
<b>Other Regulatory Liabilities:</b>		
Deferred Income Taxes	\$142,779	asset lives
South Dakota Environmental Cost Recovery Rider Accrued Refund	207	12
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up	187	24
North Dakota Renewable Resource Recovery Rider Accrued Refund	177	12
South Dakota Transmission Cost Recovery Rider Accrued Refund	168	12
Revenue for Rate Case Expenses Subject to Refund – Minnesota	166	see below
North Dakota Transmission Cost Recovery Rider Accrued Refund	60	12
Other	84	180
<b>Total Other Regulatory Liabilities</b>	<b>\$ 143,828</b>	
<b>Net Other Regulatory Asset/(Liability) Position</b>	<b>\$ 4,637</b>	

<sup>1</sup>Costs subject to recovery without a rate of return.

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

<sup>1</sup>Costs subject to recovery without a rate of return.

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

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 Asset Retirement Obligation (ARO) Accretion/Depreciation Adjustment will accrete and be amortized over the lives of property with asset retirement obligations.

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

All Deferred Marked-to-Market Losses recorded as of December 31, 2018 relate to forward purchases of energy scheduled for delivery through December 2020.

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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 beginning with the establishment of interim rates in January 2018.

Minnesota Renewable Resource Recovery Rider Accrued Revenues relate to an increase in renewable revenue requirements resulting from the expiration of tax credits for certain wind turbines. The balance represents amounts subject to recovery from Minnesota customers that have not been billed to Minnesota customers as of December 31, 2018.

The Minnesota Transmission Cost Recovery Rider Accrued Revenues relate to revenues earned on qualifying transmission system facilities and operating costs incurred to serve Minnesota customers that are recoverable from Minnesota customers as of December 31, 2018.

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.

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

South Dakota Deferred Rate Case Expenses Subject to Recovery relate to costs incurred in conjunction with OTP's current rate case in South Dakota and are currently being recovered beginning with the establishment of interim rates in October 2018.

The Minnesota SPP Transmission Cost Recovery Tracker regulatory asset relates to costs incurred to serve Minnesota customers that are subject to recovery but that have not been billed to Minnesota customers as of December 31, 2018.

The Minnesota Environmental Cost Recovery Rider Accrued Revenues relate to revenues earned on the Minnesota share of OTP's investment in the Big Stone Plant AQCS project that are recoverable from Minnesota customers as of December 31, 2018.

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, 2018.

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

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

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, 2018.

North Dakota Renewable Resource Recovery Rider Accrued Refund relates to amounts collected for qualifying renewable resource costs incurred to serve North Dakota customers that are refundable to North Dakota customers as of December 31, 2018.

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, 2018.

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 were subject to refund over a 24-month period

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beginning with the establishment of interim rates in April 2016.

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, 2018.

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 were 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 were refundable to Minnesota customers as of December 31, 2017.

The Minnesota Renewable Resource Recovery Rider Accrued Refund relates to amounts collected for qualifying renewable resource costs incurred to serve Minnesota customers that were refundable to Minnesota 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 its 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

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 \$25 million in 2018 and \$0 in 2017.

#### 5. Retained Earnings and Dividend Restriction

OTP 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, 2018, OTP was in compliance with these financial covenants. See note 8 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 47.9% and 58.5% based on OTP's 2018 capital structure petition effective by order of the MPUC on October 18, 2018. As of December 31, 2018, OTP's equity-to-total-capitalization ratio including short-term debt was 53.2% and its net assets restricted from distribution totaled approximately \$477 million. Total capitalization for OTP cannot currently exceed \$1.2 billion.

#### 6. Leases

OTP has obligations to make future operating lease payments primarily related to coal rail-car leases. OTP's rail car lease payments are charged to fuel inventory and then expensed to production fuel as a component of fuel cost when fuel is burned. OTP also leases office and operating equipment with lease payments charged to rent expense and reported in other operation and maintenance expenses in the statements of income. From time to time, OTP will lease construction equipment or land for lay-down yards for materials used on capital projects. These leases are generally short term in nature with the lease payments being charged to the related construction project and included in construction work in progress or plant in service after the project is completed and placed in service. OTP currently has no assets held under capital leases.

Lease payment expenses including payments for rail car leases totaled \$1,287,000 in 2018 and \$1,667,000 in 2017.

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The amounts of OTP's future operating leases obligations as of December 31, 2018 are as follows:

<i>(in thousands)</i>	
2019	\$ 1,099
2020	1,077
2021	1,047
2022	214
2023	196
Beyond 2023	448
Total	\$ 4,081

In February 2016, the FASB issued ASU No. 2016-02. The new standard requires lessees to record assets and liabilities on the balance sheet for all leases with terms longer than 12 months. Leases will be classified as either finance or operating, with classification affecting the pattern of expense recognition in the income statement.

OTP adopted the new standard on January 1, 2019 as required under GAAP. OTP elected the package of practical expedients permitted under the transition guidance within the new standard, which among other things, allows for the carry forward of historical lease classifications determined under the requirements of ASC Topic 840. OTP has also elected the practical expedient related to land easements, allowing for the continuation of historical current accounting treatment for land easements on existing agreements. In addition, OTP has elected the hindsight practical expedient to determine the reasonably certain lease term for existing leases.

On implementation of the new lease accounting standard, ASC Topic 842, *Leases*, in January 2019, the majority of OTP's leased assets will be capitalized as right-of-use operating assets. Certain leases that are short-term in nature—less than one year—will not be capitalized as a policy election and the associated rent payments will continue to be charged directly to rent expense. Payment for certain other leases with immaterial obligations in the aggregate relative to the obligations associated with capitalized right-of-use operating assets will also not be capitalized but will continue to be charged directly to rent expense on a straight-line basis.

Leases in place at the time of adoption will be capitalized on the basis of their remaining payment obligation balances, discounted to present value based on an explicit or implicit borrowing rate or on OTP's incremental borrowing rate appropriate to the leased asset and lease terms. The remaining payments for operating lease right-of-use assets will be charged to expense on a straight-line basis over the life of the lease beginning in January 2019.

OTP estimates adoption of the standard will result in recognition of net lease assets and lease liabilities of approximately \$3.4 million on January 1, 2019. OTP believes adoption of the new standard will not have a material effect on its liquidity and the standard is not expected to have an impact on OTP's debt-covenant compliance under its current debt agreements.

Because the leases to be capitalized as right of use assets under ASC Topic 842 are operating leases and were operating leases under ASC Topic 840, the adoption of the new standard will have no material impact on OTP's statements of income or cash flows.

## 7. Commitments and Contingencies

### Construction and Other Purchase Commitments

At December 31, 2018 OTP had commitments under contracts, including its share of construction program commitments and other nonlease commitments, extending into 2021 of approximately \$64.5 million. OTP's other nonlease commitments charged to rent expense totaled \$252,000 in 2018 and \$280,000 in 2017.

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#### 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 also has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. OTP's current coal purchase agreements for Coyote Station expire at the end of 2040. OTP's current coal purchase agreements for Big Stone Plant expire at the end of 2020. OTP entered into a coal purchase agreement with Peabody COALSALES, LLC effective May 14, 2018 for the purchase of subbituminous coal for Big Stone Plant's coal requirements through December 31, 2020. There is no fixed minimum purchase requirement under this agreement but all of Big Stone Plant's coal requirements for the period covered must be purchased under this agreement, except for the portion contracted to be purchased in 2019 under an existing agreement with Contura Coal Sales, LLC. OTP has an all-requirements agreement with Cloud Peak Energy Resources LLC for the purchase of subbituminous coal for Hoot Lake Plant through December 31, 2023. There are no fixed minimum purchase requirements under this agreement.

#### OTP Land Easements

OTP has commitments to make future payments for land easements not classified as leases. Land easement payments charged to rent expense totaled \$605,000 in 2018 and \$593,000 in 2017.

The amounts of the OTP's construction program and other commitments and commitments under capacity and energy agreements, coal purchase and coal delivery contracts and land easements as of December 31, 2018, are as follows:

<i>(in thousands)</i>	Construction Program and Other Commitments	Capacity and Energy Requirements	Coal Purchase Commitments	OTP Land Easement Payments
2019	\$ 42,277	\$ 24,925	\$ 23,397	\$ 617
2020	22,259	24,844	22,645	630
2021	1	12,988	22,935	642
2022	--	11,827	22,793	655
2023	--	11,827	23,955	668
Beyond 2023	--	143,099	503,492	7,612
Total	\$ 64,537	\$ 229,510	\$ 619,217	\$ 10,824

#### Contingencies

OTP had a \$1.6 million refund liability on its balance sheet as of December 31, 2018 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. As discussed in Note 2 in greater detail, OTP believes its estimated accrued refund liability is appropriate based on the current facts and circumstances and is awaiting further action by the FERC before determining if a change in this estimate will be needed.

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.

In 2015 the Environmental Protection Agency (EPA), acting under Section 111(d) of the Clean Air Act, issued the Clean Power Plan which required states to submit plans to limit carbon dioxide emissions from certain fossil fuel-fired power plants. The rule is not currently in effect as a result of a stay by the Supreme Court in 2016. In 2017, the EPA issued a Notice of Proposed Rulemaking to repeal the Clean Power Plan; comments were due in April 2018.

On August 21, 2018 the EPA proposed a replacement for the Clean Power Plan -- the Affordable Clean Energy (ACE) Rule. Among other things, the ACE Rule determines that the best system of emission reduction for greenhouse gas emissions from coal-fired power plants is to improve the plants' heat rates, identifies a list of "candidate technologies" for improving a plant's heat rate and proposes that physical or operational changes to a power plant would not be a "major modification" triggering extensive New Source Review, if the change does increase hourly emissions. If the ACE Rule goes into effect, states will have three years after the final rule to submit a state implementation plan.

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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 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, 2018 will not be material.

**8. 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, 2018 and December 31, 2017:

<i>(in thousands)</i>	Line Limit	In Use on December 31, 2018	Restricted due to Outstanding Letters of Credit	Available on December 31, 2018	Available on December 31, 2017
OTP Credit Agreement	\$ 170,000	\$ 9,384	\$ 300	\$ 160,316	\$ 57,329

Under the OTP Credit Agreement (as defined below), the maximum amount of debt outstanding in 2018 was \$122.0 million on January 16, 2018 and the average daily balance of debt outstanding during 2018 was \$21.6 million. The weighted average interest rate paid on debt outstanding under the OTP Credit Agreement during 2018 was 3.0% compared with 2.4% in 2017. The weighted average interest rate on OTP’s short-term debt outstanding on December 31, 2018 was 3.7%.

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, 2018 the OTP Credit Agreement was amended to extend its expiration date by one year from October 31, 2022 to October 31, 2023. 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.

The OTP Credit Agreement currently expires on October 31, 2023. Borrowings under this agreement currently use LIBOR as the base to determine the applicable interest rate. LIBOR is currently expected to be eliminated by January 1, 2022. The OTP Credit Agreement contains a provision to determine how interest rates will be established in the event a replacement for LIBOR has not been identified before the agreement expires. The process calls for the parties to jointly agree on an alternate rate of interest to LIBOR, such as the Secured Overnight Financing Rate, that gives due consideration to prevailing market convention for determining a rate of interest for syndicated loans in the United States at such time. The parties will enter into an amendment to the agreement to reflect any alternate rate of interest and other related changes to the agreement as may be applicable. If for any reason an agreement cannot be reached on an alternate rate of interest, then any borrowings under the agreement will be determined using the Prime Rate plus a margin based on OTP’s long-term debt ratings at the time of the borrowings. If the alternate rate of interest agreed to by the parties is less than zero, such rate shall be deemed to be zero for the purposes of the credit agreement.

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## 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 outstanding borrowings under the OTP Credit Agreement.

OTP may prepay all or any part of the 2018 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 2018 Note Purchase Agreement, any prepayment made by OTP of all of the 2018 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 2018 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 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 (an 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 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

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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 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 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, 2018 for each of the next five years are:

<i>(in thousands)</i>	2019	2020	2021	2022	2023
Aggregate Amounts of Debt Maturities	\$ --	\$ --	\$140,000	\$30,000	\$ --

#### **Financial Covenants**

OTP was in compliance with the financial covenants in its debt agreements as of December 31, 2018.

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.

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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 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.

## 9. 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:

<i>(in thousands)</i>	2018	2017
Service Cost—Benefit Earned During the Period	\$ 6,298	\$ 5,494
Interest Cost on Projected Benefit Obligation	13,115	13,800
Expected Return on Assets	(20,669)	(18,768)
Amortization of Prior-Service Cost from Regulatory Asset	16	120
Amortization of Net Actuarial Loss from Regulatory Asset	7,135	5,090
Net Periodic Pension Cost <sup>1</sup>	\$ 5,895	\$ 5,736

#### <sup>1</sup>Allocation of Costs:

<i>Costs included in OTP Capital Expenditures</i>	\$ 1,443	\$ 1,142
<i>Costs included in other operation and maintenance expenses</i>	4,452	4,594

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

	2018	2017
Discount Rate	3.90%	4.60%
Long-Term Rate of Return on Plan Assets	7.50%	7.50%
Rate of Increase in Future Compensation Level	See below	3.00%
Participants to Age 39	4.50%	
Participants Age 40 to Age 49	3.50%	
Participants Age 50 and Older	2.75%	

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

<i>(in thousands)</i>	2018	2017
Regulatory Assets:		
Unrecognized Prior Service Cost	\$ 5	\$ 21
Unrecognized Actuarial Loss	104,891	99,360
Total Regulatory Assets	\$ 104,896	\$ 99,381
Noncurrent Liability	\$ 57,193	\$ 65,782

Funded status as of December 31:

<i>(in thousands)</i>	2018	2017
Accumulated Benefit Obligation	\$(290,522)	\$(308,509)
Projected Benefit Obligation	\$(320,231)	\$(344,253)
Fair Value of Plan Assets	263,038	278,471
Funded Status	\$ (57,193)	\$ (65,782)

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, 2018:

<i>(in thousands)</i>	2018	2017
Reconciliation of OTP's Portion of the Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	\$ 278,471	\$ 248,241
Actual Return on Plan Assets	(21,514)	43,312
Discretionary Company Contributions	20,000	--
Benefit Payments	(13,919)	(13,082)
Fair Value of Plan Assets at December 31	\$ 263,038	\$ 278,471
Estimated Asset Return	(7.3%)	17.8%
Reconciliation of OTP's Portion of the Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	\$ 344,253	\$ 307,086
Service Cost	6,298	5,494
Interest Cost	13,115	13,800
Benefit Payments	(13,919)	(13,082)
Actuarial (Gain) Loss	(29,516)	30,955
Projected Benefit Obligation at December 31	\$ 320,231	\$ 344,253

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

	2018	2017
Discount Rate	4.50%	3.90%
Rate of Increase in Future Compensation Level:		
All participants – prior to 2017		
Participants to Age 39	4.50%	4.50%
Participants Age 40 to Age 49	3.50%	3.50%
Participants Age 50 and Older	2.75%	2.75%

The assumed rate of return on pension fund assets used for the determination of 2019 net periodic pension cost is 7.25%. 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

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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:	2018	2017
Net Periodic Pension Cost	January 1, 2018	January 1, 2017
End of Year Benefit Obligations	January 1, 2018 projected to December 31, 2018	January 1, 2017 projected to December 31, 2017
Market Value of Assets	December 31, 2018	December 31, 2017

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 2019 are:

<i>(in thousands)</i>	2019
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	\$ 5
Amortization of Unrecognized Actuarial Loss	4,642
<b>Total Estimated Amortization</b>	<b>\$ 4,647</b>

Cash flows—OTP had no minimum funding requirement as of December 31, 2018 but made discretionary plan contributions of \$10 million as of April 16, 2019.

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

<i>(in thousands)</i>	2019	2020	2021	2022	2023	Years 2024-2028
	\$14,786	\$15,377	\$16,030	\$16,679	\$17,357	\$94,272

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.

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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, 2018 and 2017, by asset category are as follows:

Asset Allocation	2018	2017
Large Capitalization Equity Securities	17.5%	23.5%
International Equity Securities	17.0%	18.1%
Small and Mid-Capitalization Equity Securities	6.7%	8.7%
SEI Dynamic Asset Allocation Fund	4.0%	5.0%
Emerging Markets Equity Fund	3.4%	5.5%
Equity Securities	48.6%	60.8%
Fixed-Income Securities and Cash	47.1%	35.2%
Other – SEI Energy Debt Collective Fund	4.3%	4.0%
	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:

(in thousands)	2018	2017
Assets in Level 1 of the Fair Value Hierarchy	\$ 251,850	\$ 267,423
SEI Energy Debt Collective Fund at NAV	11,188	11,048
Total Assets	\$ 263,038	\$ 278,471

#### 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.

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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>	2018	2017
Large Capitalization Equity Securities Mutual Fund	\$ 46,018	\$ 65,339
International Equity Securities Mutual Funds	44,764	50,397
Small and Mid-Capitalization Equity Securities Mutual Fund	17,522	24,252
SEI Dynamic Asset Allocation Mutual Fund	10,655	14,026
Emerging Markets Equity Fund	8,968	15,444
Fixed Income Securities Mutual Funds	123,921	97,964
Cash Management – Money Market Fund	2	1
Total Assets	\$ 251,850	\$ 267,423

The investments held by the SEI Energy Debt Collective Fund on December 31, 2018 and 2017 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. Otter Tail Corporation invested \$10.0 million 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 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:

<i>(in thousands)</i>	2018	2017
Service Cost–Benefit Earned During the Period	\$ 99	\$ 94
Interest Cost on Projected Benefit Obligation	679	763
Amortization of Prior Service Cost <sup>1</sup> :		
From Regulatory Asset	12	16
From Other Comprehensive Income	19	15
Amortization of Net Actuarial Loss <sup>1</sup> :		
From Regulatory Asset	214	285
From Other Comprehensive Income	321	265
Net Periodic Pension Cost <sup>2</sup>	\$ 1,344	\$ 1,438

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

<sup>2</sup>ESSRP costs are not capitalized

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

	2018	2017
Discount Rate	3.85%	4.60%
Rate of Increase in Future Compensation Level	2.75%	3.00%

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

<i>(in thousands)</i>	2018	2017
Regulatory Assets:		
Unrecognized Prior Service Cost	\$ 20	\$ 40
Unrecognized Actuarial Loss	1,768	3,229
Total Regulatory Assets	\$ 1,788	\$ 3,269
Projected Benefit Obligation Liability – Net Amount Recognized	\$(16,330)	\$(18,380)
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	\$ 29	\$ 40
Unrecognized Actuarial Loss	2,653	3,229
Total Accumulated Other Comprehensive Loss	\$ 2,682	\$ 3,269

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, 2018 and a statement of the funded status as of December 31 of both years:

<i>(in thousands)</i>	2018	2017
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	1,326	1,175
Benefit Payments	(1,326)	(1,175)
Fair Value of Plan Assets at December 31	\$ --	\$ --
Reconciliation of OTP's Portion of the Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	\$ 18,380	\$ 17,263
Service Cost	99	94
Interest Cost	679	763
Benefit Payments	(1,326)	(1,175)
Actuarial (Gain) Loss	(1,502)	1,435
Projected Benefit Obligation at December 31	\$ 16,330	\$ 18,380

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

	2018	2017
Discount Rate	4.46%	3.85%
Rate of Increase in Future Compensation Level	2.75%	2.75%

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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 2019 are:

<i>(in thousands)</i>	2019
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	\$ 5
Amortization of Unrecognized Actuarial Loss	124
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	8
Amortization of Unrecognized Actuarial Loss	186
<b>Total Estimated Amortization</b>	<b>\$ 323</b>

**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>	2019	2020	2021	2022	2023	Years 2024-2028
	\$1,269	\$1,327	\$1,284	\$1,240	\$1,194	\$5,324

#### **Other Postretirement Benefits**

OTP provides a portion of health insurance benefits for retired OTP employees. The retiree health insurance benefits will be available for all OTP nonunion employees hired prior to September 1, 2006, and all union employees of OTP hired prior to November 1, 2010, excluding Coyote Station employees. Coyote Station employees hired before January 1, 2009 are covered under the plan. To be eligible for retiree health insurance benefits the employee must be 55 years of age with a minimum of 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>	2018	2017
Service Cost—Benefit Earned During the Period	\$ 1,488	\$ 1,391
Interest Cost on Projected Benefit Obligation	2,518	2,647
Amortization of Prior Service Cost from Regulatory Asset	--	(4)
Amortization of Net Actuarial Loss from Regulatory Asset	1,648	936
<b>Net Periodic Postretirement Benefit Cost<sup>1</sup></b>	<b>\$ 5,654</b>	<b>\$ 4,970</b>
Effect of Medicare Part D Subsidy	\$ (458)	\$ (547)
<sup>1</sup> <i>Allocation of Costs:</i>		
Costs included in OTP Capital Expenditures	\$ 1,384	\$ 989
Costs included in other operation and maintenance expenses	4,270	3,981

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

	2018	2017
Discount Rate	3.81%	4.46%

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

<i>(in thousands)</i>	2018	2017
Regulatory Asset:		
Unrecognized Net Actuarial Loss	\$ 18,094	\$ 18,927
Net Regulatory Asset	\$ 18,094	\$ 18,927
Projected Benefit Obligation Liability – Net Amount Recognized	\$ (69,772)	\$ (68,100)

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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, 2018:

<i>(in thousands)</i>	2018	2017
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	3,149	3,284
Benefit Payments (Net of Medicare Part D Subsidy)	(6,625)	(6,512)
Participant Premium Payments	3,476	3,228
Fair Value of Plan Assets at December 31	\$ --	\$ --
Reconciliation of OTP's Portion of the Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	\$ 68,100	\$ 61,070
Service Cost (Net of Medicare Part D Subsidy)	1,488	1,391
Interest Cost (Net of Medicare Part D Subsidy)	2,518	2,647
Benefit Payments (Net of Medicare Part D Subsidy)	(6,625)	(6,512)
Participant Premium Payments	3,476	3,228
Actuarial Loss	815	6,276
Projected Benefit Obligation at December 31	\$ 69,772	\$ 68,100

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

	2018	2017
Discount Rate	4.44%	3.81%

Assumed healthcare cost-trend rates as of December 31:

	2018	2017
Healthcare Cost-Trend Rate Assumed for Next Year Pre-65	7.00%	5.85%
Healthcare Cost-Trend Rate Assumed for Next Year Post-65	7.00%	6.03%
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 2018 would have the following effects:

<i>(in thousands)</i>	1 Point Increase	1 Point Decrease
Effect on the Postretirement Benefit Obligation	\$ 8,868	\$ (7,396)
Effect on Total of Service and Interest Cost	\$ 739	\$ (585)
Effect on Expense	\$ 1,904	\$ (1,549)

Measurement Dates:	2018	2017
Net Periodic Postretirement Benefit Cost	January 1, 2018	January 1, 2017
End of Year Benefit Obligations	January 1, 2018 projected to December 31, 2018	January 1, 2017 projected to December 31, 2017

The estimated net amounts of unrecognized accumulated actuarial losses to be amortized from regulatory assets into the net periodic postretirement benefit cost in 2019 is \$1,570,000.

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NOTES TO FINANCIAL STATEMENTS (Continued)			

**Cash flows**—OTP expects to contribute \$4.1 million net of expected employee contributions for the payment of retiree medical benefits and Medicare Part D subsidy receipts in 2019. OTP expects to receive a Medicare Part D subsidy from the Federal government of approximately \$415,000 in 2019. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

<i>(in thousands)</i>	2019	2020	2021	2022	2023	Years 2024-2028
	\$4,141	\$4,214	\$4,371	\$4,581	\$4,662	\$23,579

#### **401K Plan**

OTP has a 401K plan for the benefit of all its employees. Contributions made to this plan by OTP totaled \$2,646,000 for 2018 and \$2,381,000 for 2017.

#### **Employee Stock Ownership Plan**

OTP has a stock ownership plan for the benefit of all its employees. Contributions made by OTP were \$398,000 for 2018 and \$612,000 for 2017.

### **10. 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, 2018 and 2017 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, 2018		December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Short-term investments	\$ 15	\$ 15	\$ 22	\$ 22
Short-Term Debt	(9,384)	(9,384)	(112,371)	(112,371)
Long-Term Debt including Current Maturities	(512,000)	(529,738)	(412,000)	(469,180)

### **11. Property, Plant and Equipment**

<i>(in thousands)</i>	December 31, 2018	December 31, 2017	Service Life Range <i>(years)</i>	
			Low	High
<b>Electric Plant in Service</b>				
Production	\$ 905,249	\$ 897,732	9	82
Transmission	512,977	500,352	42	70
Distribution	502,473	482,867	5	68
General	99,453	100,067	5	50
Electric Plant in Service	2,020,152	1,981,018		
Construction Work in Progress	170,614	132,556		
Total Gross Electric Plant	2,190,767	2,113,574		
Less Accumulated Depreciation and Amortization	782,871	745,531		
Net Electric Plant	\$ 1,407,896	\$ 1,368,043		

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NOTES TO FINANCIAL STATEMENTS (Continued)			

The estimated service lives for rate-regulated properties is 5 to 82 years.

## 12. Income Taxes

The total income tax expense differs from the amount computed by applying the federal income tax rate (21% in 2018 and 35% in 2017) to net income before total income tax expense for the following reasons:

<i>(in thousands)</i>	2018	2017
Tax Computed at Federal Statutory Rate	\$ 12,624	\$ 23,261
Increases (Decreases) in Tax from:		
State Income Taxes Net of Federal Income Tax Benefit	2,100	2,769
Differences Reversing in Excess of Federal Rates	(3,432)	551
Federal Production Tax Credit	(3,111)	(7,527)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(850)	(850)
Dividend Received/Paid Deduction	(298)	(509)
Investment Tax Credit Amortization	(98)	(164)
Allowance for Funds Used During Construction - Equity	(431)	(322)
Effect of TCJA	--	458
Permanent and Other Differences	(820)	(654)
<b>Total Income Tax Expense</b>	<b>\$ 5,684</b>	<b>\$ 17,013</b>
Overall Effective Federal and State Income Tax Rate	9.5%	25.6%
Income Tax Expense Includes the Following:		
Current Federal Income Taxes	\$ 2,690	\$ (291)
Current State Income Taxes	817	784
Deferred Federal Income Taxes	4,105	21,583
Deferred State Income Taxes	2,131	3,478
Federal Production Tax Credit	(3,111)	(7,527)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(850)	(850)
Investment Tax Credit Amortization	(98)	(164)
<b>Total</b>	<b>\$ 5,684</b>	<b>\$ 17,013</b>
<b>Total Income Before Income Taxes</b>	<b>\$ 60,115</b>	<b>\$ 66,459</b>

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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>	2018		2017	
<b>Deferred Tax Assets</b>				
Federal Production Tax Credits (PTCs)	\$	36,199	\$	40,640
North Dakota Wind Tax Credits		35,520		35,794
Benefit Liabilities		14,709		18,776
Differences Related to Property		5,655		5,420
Net Operating Loss Carryforward		1,465		845
Vacation Accrual		1,128		1,142
Investment Tax Credits		449		515
Other		3,406		560
<b>Total Deferred Tax Assets</b>	<b>\$</b>	<b>98,531</b>	<b>\$</b>	<b>103,692</b>
<b>Deferred Tax Liabilities</b>				
Differences Related to Property	\$	(180,541)	\$	(179,929)
Excess Tax over Book Pension		(15,145)		(14,077)
North Dakota Wind Tax Credits		(6,925)		(6,926)
AQCS Section 169		(6,413)		(3,263)
Regulatory Asset		(3,963)		(2,279)
Renewable Resource Rider Accrued Revenue		(228)		(164)
Impact of State Net Operating Losses on		(311)		(487)
Federal Taxes		(311)		(487)
Other		(216)		1,010
<b>Total Deferred Tax Liabilities</b>	<b>\$</b>	<b>(213,742)</b>	<b>\$</b>	<b>(206,115)</b>
<b>Deferred Income Taxes</b>	<b>\$</b>	<b>(115,211)</b>	<b>\$</b>	<b>(102,423)</b>

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 decreased 53.0% in 2018 compared with 2017. 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.

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NOTES TO FINANCIAL STATEMENTS (Continued)			

Schedule of expiration of tax credits and tax net operating losses available as of December 31, 2018:

<i>(in thousands)</i>	Amount	2029-37	2038-43
<b>United States</b>			
Federal Tax Credits	\$ 36,199	\$ 36,199	\$ --
State Net Operating Losses	1,465	1,465	--
State Tax Credits	32,962	--	32,962

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

<i>(in thousands)</i>	2018	2017
Balance on January 1	\$ 120	\$ 411
(Decreases) Increases Related to Tax Positions for Prior Years	--	(291)
Increases Related to Tax Positions for Current Year	--	--
Uncertain Positions Resolved During Year	(69)	--
Balance on December 31	\$ 51	\$ 120

The balance of unrecognized tax benefits as of December 31, 2018 would reduce the OTP's effective tax rate if recognized. The total amount of unrecognized tax benefits as of December 31, 2018 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, 2018.

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, 2018, with limited exceptions, Otter Tail Corporation is no longer subject to examinations by taxing authorities for tax years prior to 2015 for federal and North Dakota state income taxes and for years prior to 2014 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 Securities and Exchange Commission staff guidance for the application of ASC Topic 740, *Income Taxes*, and allowed up to one year to complete the required analyses and accounting for the TCJA. At December 31, 2017 OTP was able to make reasonable estimates of the impact of the TCJA for the reduction in the federal corporate tax rate, changes to bonus depreciation and consequences on OTP's regulatory liabilities. The accounting for the income tax effects of the enactment of the TCJA was complete as

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NOTES TO FINANCIAL STATEMENTS (Continued)			

of September 30, 2018. OTP did not make any material adjustments in 2018 to the amounts recorded at December 31, 2017.

### 13. 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 2018.

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, 2018 and 2017 are presented in the following table:

<i>(in thousands)</i>	2018	2017
<u>Asset Retirement Obligations</u>		
Beginning Balance	\$ 8,719	\$ 8,341
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	--
Accrued Accretion	398	378
Settlements	--	--
Ending Balance	\$ 9,117	\$ 8,719
<u>Asset Retirement Costs Capitalized</u>		
Beginning Balance	\$ 2,983	\$ 2,983
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	--
Settlements	--	--
Ending Balance	\$ 2,983	\$ 2,983
<u>Accumulated Depreciation – Asset Retirement Costs Capitalized</u>		
Beginning Balance	\$ 915	\$ 795
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	--
Depreciation Expense	119	120
Settlements	--	--
Ending Balance	\$ 1,034	\$ 915
<u>Settlements</u>		
Original Capitalized Asset Retirement Cost – Retired	\$ --	\$ --
Accumulated Depreciation	--	--
Asset Retirement Obligation	\$ --	\$ --
Settlement Cost	--	--
Gain on Settlement – Deferred Under Regulatory Accounting	\$ --	\$ --





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)	2,000,121,465	2,000,121,465
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	18,354,025	18,354,025
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	2,018,475,490	2,018,475,490
9	Leased to Others		
10	Held for Future Use	29,656	29,656
11	Construction Work in Progress	170,614,396	170,614,396
12	Acquisition Adjustments	1,647,128	1,647,128
13	Total Utility Plant (8 thru 12)	2,190,766,670	2,190,766,670
14	Accum Prov for Depr, Amort, & Depl	782,870,571	782,870,571
15	Net Utility Plant (13 less 14)	1,407,896,099	1,407,896,099
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	776,809,794	776,809,794
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	4,413,649	4,413,649
22	Total In Service (18 thru 21)	781,223,443	781,223,443
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)	782,870,571	782,870,571

Name of Respondent  
Otter Tail Power Company

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

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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
					6
					7
					8
					9
					10
					11
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					14
					15
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					29
					30
					31
					32
					33

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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, 2017	1,979,341,336
January 31, 2018	1,979,302,260
February 28, 2018	1,980,038,714
March 31, 2018	1,984,728,134
April 30, 2018	1,986,117,124
May 31, 2018	1,987,025,513
June 30, 2018	1,992,103,703
July 31, 2018	1,995,603,573
August 31, 2018	1,997,778,563
September 30, 2018	1,998,697,329
October 31, 2018	2,000,481,306
November 30, 2018	2,006,380,414
December 31, 2018	2,018,475,490
13-month average for rate-making	1,992,774,881

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

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

	Account 107 Balance	CWIP not in Rates	CWIP in Rate Base
December 31, 2017	132,556,715	45,747,372	86,809,343
January 31, 2018	137,360,199	48,102,063	89,258,136
February 28, 2018	143,866,688	51,495,937	92,370,751
March 31, 2018	144,509,725	51,718,794	92,790,931
April 30, 2018	150,322,695	57,117,797	93,204,898
May 31, 2018	156,367,477	61,294,611	95,072,866
June 30, 2018	158,796,906	62,399,839	96,397,067
July 31, 2018	162,004,150	64,295,352	97,708,798
August 31, 2018	167,656,946	68,500,094	99,156,852
September 30, 2018	173,904,174	73,477,976	100,426,198
October 31, 2018	180,450,323	78,778,650	101,671,673
November 30, 2018	179,046,963	76,427,507	102,619,456
December 31, 2018	170,614,396	67,378,082	103,236,314
13-month average for rate-making			96,209,483

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:

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(2)  A Resubmission

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(Mo, Da, Yr)

12/31/2018

Year/Period of Report

End of 2018/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance End of Year (f)	Line No.
Amortization (d)	Other Reductions (Explain in a footnote) (e)		
			1
			2
			3
			4
			5
			6
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			10
			11
			12
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			21
			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) 12/31/2018	Year/Period of Report 2018/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	9,905,744	3,135,454
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	11,207,718	3,135,454
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,654,157	
9	(311) Structures and Improvements	125,777,776	-5,700,687
10	(312) Boiler Plant Equipment	337,846,093	14,332,321
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	65,986,582	89,744
13	(315) Accessory Electric Equipment	36,710,491	-1,100,806
14	(316) Misc. Power Plant Equipment	6,555,651	272,970
15	(317) Asset Retirement Costs for Steam Production	2,758,152	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	577,288,902	7,893,542
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	351,712	
29	(332) Reservoirs, Dams, and Waterways	4,277,054	
30	(333) Water Wheels, Turbines, and Generators	1,373,867	
31	(334) Accessory Electric Equipment	597,103	
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)	7,341,983	
36	D. Other Production Plant		
37	(340) Land and Land Rights	126,762	
38	(341) Structures and Improvements	12,946,210	401,264
39	(342) Fuel Holders, Products, and Accessories	1,748,265	
40	(343) Prime Movers	32,333,938	1,022,370
41	(344) Generators	241,518,631	375,260
42	(345) Accessory Electric Equipment	20,684,147	4,615
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)	310,210,876	1,803,509
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	894,841,761	9,697,051

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	14,416,958	4,024,491
49	(352) Structures and Improvements		
50	(353) Station Equipment	121,679,913	3,313,288
51	(354) Towers and Fixtures	108,068,409	6,138,860
52	(355) Poles and Fixtures	117,066,299	6,934,769
53	(356) Overhead Conductors and Devices	138,975,944	-7,419,524
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)	500,284,984	12,991,884
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	1,306,581	74,763
61	(361) Structures and Improvements		
62	(362) Station Equipment	80,581,241	3,140,054
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	73,198,336	2,344,762
65	(365) Overhead Conductors and Devices	51,913,449	1,527,738
66	(366) Underground Conduit		
67	(367) Underground Conductors and Devices	77,393,275	5,573,798
68	(368) Line Transformers	97,976,904	6,210,843
69	(369) Services	55,445,389	1,469,563
70	(370) Meters	34,322,758	2,511,241
71	(371) Installations on Customer Premises	5,010,334	767,444
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	5,697,611	664,430
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	482,845,878	24,284,636
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	31,141,691	384,400
88	(391) Office Furniture and Equipment	6,374,425	1,497,798
89	(392) Transportation Equipment	35,045,822	4,993,455
90	(393) Stores Equipment		
91	(394) Tools, Shop and Garage Equipment	4,828,421	357,336
92	(395) Laboratory Equipment		
93	(396) Power Operated Equipment	621,330	299,347
94	(397) Communication Equipment	10,627,413	144,498
95	(398) Miscellaneous Equipment		
96	SUBTOTAL (Enter Total of lines 86 thru 95)	90,160,998	7,676,834
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)	90,160,998	7,676,834
100	TOTAL (Accounts 101 and 106)	1,979,341,339	57,785,859
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)	1,979,341,339	57,785,859



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
			18,441,449	48
				49
502,942		625,912	125,116,171	50
			114,207,269	51
272,517			123,728,551	52
217,405			131,339,015	53
				54
			77,461	55
				56
				57
992,864		625,912	512,909,916	58
				59
1,296		-794	1,379,254	60
				61
846,123		-654,876	82,220,296	62
				63
179,859			75,363,239	64
276,630		-5,299	53,159,258	65
				66
360,186			82,606,887	67
794,330		24,015	103,417,432	68
78,980			56,835,972	69
760,210			36,073,789	70
348,360			5,429,418	71
				72
395,449			5,966,592	73
				74
4,041,423		-636,954	502,452,137	75
				76
				77
				78
				79
				80
				81
				82
				83
				84
				85
2,500		794	1,520,190	86
46,914		6,100	31,485,277	87
1,792,204			6,080,019	88
4,537,385		-54,290	35,447,602	89
				90
244,778			4,940,979	91
				92
52,405		54,290	922,562	93
545,499			10,226,412	94
				95
7,221,685		6,894	90,623,041	96
				97
				98
7,221,685		6,894	90,623,041	99
18,651,703		1	2,018,475,496	100
				101
				102
				103
18,651,703		1	2,018,475,496	104

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

**Schedule Page: 204 Line No.: 5 Column: b**

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, 2017	11,207,717
January 31, 2018	11,257,244
February 28, 2018	11,257,244
March 31, 2018	11,310,954
April 30, 2018	11,314,282
May 31, 2018	11,314,282
June 30, 2018	11,452,175
July 31, 2018	11,452,175
August 31, 2018	11,906,102
September 30, 2018	11,909,299
October 31, 2018	11,979,796
November 30, 2018	10,411,608
December 31, 2018	10,131,644
13-month average for rate-making	11,300,348

**Schedule Page: 204 Line No.: 46 Column: b**

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, 2017	894,841,759
January 31, 2018	894,843,203
February 28, 2018	894,843,203
March 31, 2018	894,731,034
April 30, 2018	894,766,423
May 31, 2018	894,480,250
June 30, 2018	894,419,890
July 31, 2018	894,330,003
August 31, 2018	894,318,058
September 30, 2018	894,696,502
October 31, 2018	893,889,502
November 30, 2018	899,957,320
December 31, 2018	902,358,754
13-month average for rate-making	895,575,069

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

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:

	Electric Transmission Plant In Service
December 31, 2017	500,284,984
January 31, 2018	500,051,839
February 28, 2018	500,436,320
March 31, 2018	503,196,728
April 30, 2018	503,656,329
May 31, 2018	503,561,093

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) 12/31/2018	Year/Period of Report 2018/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

June 30, 2018	504,358,264
July 31, 2018	505,893,643
August 31, 2018	506,501,712
September 30, 2018	506,767,197
October 31, 2018	508,078,533
November 30, 2018	509,327,706
December 31, 2018	512,909,816
13-month average for rate-making	505,001,866

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

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, 2017	482,845,878
January 31, 2018	483,125,616
February 28, 2018	483,720,263
March 31, 2018	485,564,396
April 30, 2018	486,463,584
May 31, 2018	487,909,193
June 30, 2018	490,157,045
July 31, 2018	492,264,711
August 31, 2018	493,550,621
September 30, 2018	494,479,168
October 31, 2018	494,660,354
November 30, 2018	498,282,226
December 31, 2018	502,452,137
13-month average for rate-making	490,498,092

**Schedule Page: 204 Line No.: 99 Column: b**

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 In Service
December 31, 2017	90,160,997
January 31, 2018	90,024,358
February 28, 2018	89,781,684
March 31, 2018	89,925,019
April 30, 2018	89,916,505
May 31, 2018	89,760,695
June 30, 2018	91,716,330
July 31, 2018	91,663,040
August 31, 2018	91,502,070
September 30, 2018	90,845,163
October 31, 2018	90,873,122
November 30, 2018	88,401,554
December 31, 2018	90,623,039
13-month average for rate-making	90,399,506

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					
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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				
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9				
10				
11				
12				
13				
14				
15				
16				
17				
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20				
21	Other Property:			
22	Various			
23				
24				
25				
26				
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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) 12/31/2018	Year/Period of Report 2018/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:

	<u>Transmission</u>	<u>Distribution</u>	<u>Total</u>
December 31, 2017	9,037	20,619	29,656
January 31, 2018	9,037	20,619	29,656
February 28, 2018	9,037	20,619	29,656
March 31, 2018	9,037	20,619	29,656
April 30, 2018	9,037	20,619	29,656
May 31, 2018	9,037	20,619	29,656
June 30, 2018	9,037	20,619	29,656
July 31, 2018	9,037	20,619	29,656
August 31, 2018	9,037	20,619	29,656
September 30, 2018	9,037	20,619	29,656
October 31, 2018	9,037	20,619	29,656
November 30, 2018	9,037	20,619	29,656
December 31, 2018	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	8,406,464
2	System Wide - New Natural Gas Generation - Construct Generating Plant	8,312,880
3	Big Stone, SD - Ellendale, ND CMA - Construct Transmission Facilities	94,980,380
4	Big Stone, SD - Ellendale, ND Retention - Construct Transmission Facilities	3,102,912
5	System Wide - CISone - Purchase Intangible Plant	17,549,988
6	System Wide - FERC Hydro Re-licensing - Construct Intangible Plant	1,002,051
7	Merricourt, ND - Wind Project - Construct Generation Plant	4,938,567
8	Coyote, SD - Bottom Ash & Economizer Ash Retrofit - Construct Generating Plant	1,671,255
9	Jamestown, ND - Fleet & ASB Building - Construct Generating Plant	1,319,375
10	Lake Norden, SD - Transmission - Construct Transmission Facilities	3,596,702
11	Hetland, SD - Transmission - Construct Transmission Facilities	1,186,921
12	Hetland, SD - Lake Norden 115 kv Transmission - Construct Transmission Facilities	3,772,044
13	Lake Norden, SD - UG Facility Improvements - Construct Transmission Facilities	1,597,865
14	Total Projects under \$1,000,000	19,176,992
15		
16		
17		
18		
19		
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21		
22		
23		
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42		
43	TOTAL	170,614,396

**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	737,319,904	737,319,904		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	51,993,115	51,993,115		
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	1,922,330	1,922,330		
7	Other Clearing Accounts	-77,705	-77,705		
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	53,957,616	53,957,616		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	14,442,450	14,442,450		
13	Cost of Removal	7,864,020	7,864,020		
14	Salvage (Credit)	3,314,849	3,314,849		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	18,991,621	18,991,621		
16	Other Debit or Cr. Items (Describe, details in footnote):	4,523,895	4,523,895		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	776,809,794	776,809,794		

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

20	Steam Production	261,661,904	261,661,904		
21	Nuclear Production				
22	Hydraulic Production-Conventional	5,249,740	5,249,740		
23	Hydraulic Production-Pumped Storage				
24	Other Production	127,154,025	127,154,025		
25	Transmission	128,568,222	128,568,222		
26	Distribution	217,285,805	217,285,805		
27	Regional Transmission and Market Operation				
28	General	36,890,098	36,890,098		
29	TOTAL (Enter Total of lines 20 thru 28)	776,809,794	776,809,794		

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) 12/31/2018	Year/Period of Report 2018/Q4
Otter Tail Power Company			
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 of production, transmission, distribution and general plant for rate-making purposes, illustrated as follows for the current year:

	Production *	Transmission	Distribution	General	Total
December 31, 2017	367,618,662	120,734,336	210,361,952	38,604,955	737,319,904
January 31, 2018	370,030,987	121,454,283	211,151,840	38,755,883	741,392,993
February 28, 2018	372,443,083	122,073,979	211,791,322	38,899,224	745,207,608
March 31, 2018	374,703,981	122,634,718	212,468,143	39,267,815	749,074,657
April 30, 2018	377,115,890	123,169,781	213,088,071	39,642,519	753,016,261
May 31, 2018	379,529,451	123,556,659	213,496,293	39,833,865	756,416,268
June 30, 2018	381,877,909	124,213,012	214,490,140	39,357,355	759,938,415
July 31, 2018	384,180,738	124,710,889	215,134,771	39,711,486	763,737,883
August 31, 2018	386,322,894	125,216,294	216,077,009	39,968,367	767,584,563
September 30, 2018	388,695,410	125,863,862	217,138,952	39,427,512	771,125,736
October 31, 2018	389,956,008	127,101,725	217,486,747	39,699,741	774,244,221
November 30, 2018	392,256,230	127,828,995	217,976,617	37,015,078	775,076,920
December 31, 2018	394,065,669	128,568,222	217,285,805	36,890,098	776,809,794
13-month average for rate-making	381,445,916	124,394,366	214,457,512	39,005,684	759,303,479

\* 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			
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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
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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) 12/31/2018	Year/Period of Report End of <u>2018/Q4</u>
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**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)	8,894,145	8,298,406	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)	6,672,371	6,594,206	Production
8	Transmission Plant (Estimated)	5,175,554	5,843,038	Various
9	Distribution Plant (Estimated)	7,126,388	8,724,485	Various
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	269,875	295,425	Fleet Service
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	19,244,188	21,457,154	
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)	28,138,333	29,755,560	

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) 12/31/2018	2018/Q4
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, 2017	6,672,371
January 31, 2018	6,629,078
February 28, 2018	6,661,644
March 31, 2018	6,694,790
April 30, 2018	6,758,411
May 31, 2018	6,640,006
June 30, 2018	6,707,646
July 31, 2018	6,802,989
August 31, 2018	6,937,945
September 30, 2018	6,796,830
October 31, 2018	6,651,510
November 30, 2018	6,613,742
December 31, 2018	6,594,206

13-month average for rate-making 6,704,705

**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, 2017	5,175,554
January 31, 2018	5,246,258
February 28, 2018	5,286,397
March 31, 2018	5,258,445
April 30, 2018	5,161,673
May 31, 2018	5,286,629
June 30, 2018	5,274,968
July 31, 2018	5,349,324
August 31, 2018	5,473,872
September 30, 2018	5,541,536
October 31, 2018	5,746,709
November 30, 2018	5,824,671
December 31, 2018	5,843,038

13-month average for rate-making 5,420,698

**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:

Distribution 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) 12/31/2018	Year/Period of Report 2018/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

December 31, 2017	7,126,388
January 31, 2018	7,298,076
February 28, 2018	7,544,735
March 31, 2018	8,063,046
April 30, 2018	8,042,798
May 31, 2018	8,091,394
June 30, 2018	7,896,246
July 31, 2018	7,660,774
August 31, 2018	8,182,585
September 30, 2018	8,050,259
October 31, 2018	8,458,066
November 30, 2018	8,663,282
December 31, 2018	8,724,485

13-month average for  
rate-making 7,984,780

**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, 2017	269,875
January 31, 2018	271,392
February 28, 2018	269,831
March 31, 2018	278,015
April 30, 2018	280,300
May 31, 2018	289,232
June 30, 2018	289,291
July 31, 2018	315,778
August 31, 2018	294,233
September 30, 2018	289,014
October 31, 2018	298,329
November 30, 2018	280,411
December 31, 2018	295,425

13-month average for  
rate-making 286,241

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		2019	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	62,014.00	15,876	14,054.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)			1,256.00	
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	10,080.00	13,379		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	51,960.00	2,497	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	12		
45	Gains	202.96	12		
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.

2020		2021		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		469,580.00	15,876	1
								2
								3
1,256.00		1,256.00		15,310.00		19,078.00		4
						26.00		5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						10,080.00	13,379	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
15,310.00		15,310.00		380,714.00		478,604.00	2,497	29
								30
								31
								32
								33
								34
								35
								36
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	4	405.92		16 44
				202.96	4	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) 12/31/2018	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

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

Includes 1,256 of initial allocations from EPA and 1,300 of rollover allowances for Cross State Air Pollution Rule.

**Schedule Page: 228 Line No.: 4 Column: d**

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

**Schedule Page: 228 Line No.: 4 Column: f**

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

**Schedule Page: 228 Line No.: 4 Column: h**

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

**Schedule Page: 228 Line No.: 4 Column: j**

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		2019	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	2,348.00			
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)			876.00	
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	806.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	1,560.00		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.

2020		2021		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
						2,348.00		1
								2
								3
876.00		876.00		876.00		3,504.00		4
						18.00		5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						806.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
876.00		876.00		876.00		5,064.00		29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

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

Includes 876 of initial allocations from EPA and 1,472 rollover allowances for Cross State Air Pollution Rule.

**Schedule Page: 229 Line No.: 4 Column: d**

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

**Schedule Page: 229 Line No.: 4 Column: f**

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

**Schedule Page: 229 Line No.: 4 Column: h**

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

**Schedule Page: 229 Line No.: 4 Column: j**

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

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) 12/31/2018	Year/Period of Report End of <u>2018/Q4</u>
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**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)  
12/31/2018

Year/Period of Report

End of 2018/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	2,285,597			656,992	1,628,605
22	-Transmission					
23	MPUC order issued 04-25-2011					
24	Remaining recovery period: 52 mos					
25						
26	BSII called project - SD	309,356		407	100,331	209,025
27	-Generation					
28	SDPUC order issued 02-11-2010					
29	Remaining recovery period: 25 mos					
30						
31	BSII cancelled project - SD	232,957				232,957
32	-Transmission					
33	SDPUC order issued 04-30-2013					
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	2,827,910			757,323	2,070,587

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) 12/31/2018	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

**Schedule Page: 230 Line No.: 21 Column: d**  
Accounts 407 and 419 were used.

**Schedule Page: 230 Line No.: 31 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	<b>Transmission Studies</b>				
2	J488/J489 Dakota Range III &	3,174	456	3,584	456
3	IV Interconnection Facility Stud				
4					
5	J526 Interconnection Facility	4,765	456	5,313	456
6	Study				
7					
8	J436/J437 Hankinson to	5,821	456	5,821	456
9	Ellendale Line Upgrade Study				
10					
11	J422 Wahpeton to Hankinson	3,493	456	3,493	456
12	Line Upgrade Study				
13					
14	J488/J493/J526 Big Stone -	2,180	456	2,180	456
15	Browns Valley Facility Study				
16					
17	G359 (J457) Hankinson -	20,307	456	19,273	456
18	Ellendale & BS-Blair FAS				
19					
20	J637 Interconnection Facility Stdy	957	456		456
21	<b>Generation Studies</b>				
22	J488, J493, J526 - BSP Xfr and	7,237	456.0	6,757	456.0
23	Blair Terminal Equipment at BSP				
24					
25	J526 Wahpeton - Fergus Falls	2,282	456.0	2,282	456.0
26					
27	J488 Hankinson to Ellendale	2,424	456.0	2,424	456.0
28					
29	J493/J526 Ortonville-Johnson-	10,500	456.0	10,500	456.0
30	Morris				
31					
32	J488/J493/J526 Hankinson-	3,217	456.0	3,217	456.0
33	Wahpeton & Blair substation				
34	switches facility study				
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		3,103,151	282	680,049	2,423,102
4						
5	Asset Retirement Obligation Capitalized					
6	Hoot Lake Plant	2,141,736	108,528			2,250,264
7	Big Stone Plant	692,089	95,001			787,090
8	Coyote Station	2,595,636	223,758			2,819,394
9	Wind Generation - Langdon	487,541	29,938	407.4	2,332	515,147
10	Wind Generation - Ashtabula	373,969	32,122	407.4	1,981	404,110
11	Wind Generation - Luverne	360,242	32,776			393,018
12						
13	Derivatives-Marked to Market Losses	6,467,562		253 & 242	4,062,921	2,404,641
14						
15	MISO Schedules 26 & 26A Accrual	56,729	240,040	See Note	56,729	240,040
16						
17	MN Renewable Resource Rider		552,330	See Note	100,199	452,131
18	ND Renewable Resource Rider	441,791		See Note	441,791	
19						
20	ESSRP	3,269,303		228.3	1,481,279	1,788,024
21						
22	Pension	99,380,760	12,666,527	228.3	7,150,875	104,896,412
23						
24	MN Transmission Revenue Rider	1,038,930	1,036,561	See Note	1,631,856	443,635
25	ND Transmission Revenue Rider	717,583	213,663	See Note	931,246	
26	SD Transmission Revenue Rider	172,235		See Note	172,235	
27						
28	Post Retirement Medical Benefits	18,926,976	815,418	228.3	1,648,131	18,094,263
29						
30	Conservation Improvement Program - MN	9,999,875	4,905,119	186	5,759,950	9,145,044
31	Energy Efficiency Program - SD	158,984	212,655	186	236,877	134,762
32						
33	MN Rate Case Expense Deferral	267,019		407.4	267,019	
34	ND Rate Case Expense Deferral	309,293	406,187	407.4	260,519	454,961
35			217,318	407.4	39,427	177,891
36	MN Environmental Cost Recovery Rider		120,725	See Note		120,725
37	ND Environmental Cost Recovery Rider	151,723	16,778	See Note	151,723	16,778
38	ADIT NOL Refund		2,739,318	407.4	2,739,318	
39	MN EITE Cost Recovery Rider	75,291	437,889	See Note	185,632	327,548
40	SPP Cost Recovery Rider		444,250	See Note	268,040	176,210
41	See footnote 3 in Notes to Financial Statements					
42	for amortization periods.					
43						
44	<b>TOTAL</b>	<b>148,085,267</b>	<b>28,650,052</b>		<b>28,270,129</b>	<b>148,465,190</b>

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) 12/31/2018	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

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

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

**Schedule Page: 232 Line No.: 17 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.: 24 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.

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

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

**Schedule Page: 232 Line No.: 39 Column: d**

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

**Schedule Page: 232 Line No.: 40 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		5,995,039	182.3	5,995,039	
3						
4	Energy Efficiency Program - SD		62	182.3	62	
5						
6	Renewable Energy Certificates	60,876	112,226			173,102
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						
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34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	60,876				173,102

**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	309,086	291,027
4	Medical Insurance Reserve		
5	Injuries and Damages Reserve		
6	See Note Below	103,382,911	98,240,541
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	103,691,997	98,531,568
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)	103,691,997	98,531,568

**Notes**

	Balance at Beginning of Year	Balance at End of Year
	-----	-----
Post Retirement Medical Benefits	22,151,116	21,617,966
Executive Supplemental Pension	4,546,574	4,307,752
Reserve for Bad Debts	447,792	352,851
Accrued Vacation Pay	1,716,537	1,610,145
Capitalized Int. on Construction	5,881,714	6,171,717
Post Employment Medical Benefits	371,238	565,385
Incentive Plans	886,324	1,096,971
Nonqualified Retirement Savings	388,172	370,123
Deferred Settlement	0	0
Federal NOL Carryforward	1,408,821	0
Excess EDIT related to Federal NOL Carryforward	0	2,398,618
Reserve for Loan Pools	4,683	4,431
Property Damage Reserves	(304,344)	16,212
Capitalized A & G	2,230,088	1,927,318
Customer Rebates Capitalized	125,038	175,494
Stock Incentives	(47,662)	50,919
Executive Restoration Plan	0	6,492
CIAC Capitalized	79,205	56,578
BSII Discount	166,821	132,739
Unicap Adjustment	36,479	33,457
Medicare Part D	446,868	424,813
Research Credit Carryforward	374,580	374,580
Flow-Through Items	79,072	114,310
State NOL Carryforward	2,301,359	1,465,416
Wind Energy Income Tax Credits-ND	35,794,016	35,519,583
ASC 740 Unamortized ITC	514,871	449,298
SFAS 109 Recognition of Regulatory Assets (Liab.)	1,899,424	1,540,340
Excess Accum Defrd Tax due to Federal Rate Change	(18,755,431)	(18,741,657)
Wind Production Tax Credit Deferral (Asset)	40,639,556	36,198,690
	-----	-----
	103,382,911	98,240,541

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		
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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)  
12/31/2018

Year/Period of Report  
End of 2018/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
						7
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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	376,988,966
2	Additional parent investment	25,000,000
3		
4		
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40	TOTAL	401,988,966

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) 12/31/2018	Year/Period of Report End of <u>2018/Q4</u>
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**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		
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10		
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12		
13	Cumulative Preferred Shares	
14		
15		
16		
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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 4.07%, Series A	100,000,000	511,350
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	512,000,000	3,486,917

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
02/07/2018	02/07/2048	02/07/2018	02/07/2048	100,000,000	3,651,694	14
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				512,000,000	25,620,094	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) 12/31/2018	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

**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)	54,430,636
2		
3		
4	Taxable Income Not Reported on Books	
5	Interest Capitalized on Construction	2,024,271
6	Net Gain from Property Retirements	1,923,804
7	Miscellaneous Taxable Items	
8	Conservation Improvement Programs	61,890
9	Deductions Recorded on Books Not Deducted for Return	
10	Add Back Federal Income Taxes (Includes Deferred & ITC Adj)	5,684,496
11	Provision for Reserves	11,169,688
12	Miscellaneous Unallowed Deductions	43,018,628
13		
14	Income Recorded on Books Not Included in Return	
15	Tax Exempt Interest	
16	Equity in Earnings of Subsidiaries	
17	Wind Rider Revenue	11,596,103
18	Miscellaneous Income Not Taxable	
19	Deductions on Return Not Charged Against Book Income	
20	Excess Tax Depreciation Over Book Depreciation	-13,362,674
21	Removal Costs	3,150,465
22	Charges to Reserves	6,548,867
23	Leveraged ESOP Deduction	1,520,717
24	Sec 481(a) Cap to Repair Basis Adjustments	
25	Miscellaneous Other Deductions	42,454,895
26		
27	Federal Tax Net Income	66,405,040
28	Show Computation of Tax:	
29	Federal Tax	13,945,058
30	Tax (Credits) and Adjustments	-7,551,428
31	Prior Period Adjustments	629,601
32	Transfer Net Operating Loss to Deferred Carryforward	-3,876,486
33	Total Federal Income Tax	3,146,745
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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) 12/31/2018	2018/Q4
FOOTNOTE DATA			

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

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME  
FOR FEDERAL INCOME TAXES (Continued)

Otter Tail Power Company is a member of an affiliated group which will file a consolidated Federal Income Tax Return for the year 2018. The other members of the affiliated group and their respective federal income tax provisions are as follows:

Otter Tail Corporation	(2,820,707)
Varistar Corporation	(4,772)
IMD, Inc.	0
BTD Manufacturing, Inc.	1,176,269
Northern Pipe Products, Inc.	3,102,369
Vinyltech Corporation	3,570,197
Otter Tail Energy Services Company	0
T. O. Plastics, Inc.	467,367
Shrco, Inc.	(13,810)
Otter Tail Assurance Limited	196,749
AEV, Inc.	0
ASI, Inc.	0
Total	<u>5,673,662</u>

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			13,945,056	11,427,915	
3	Unemployment	524		35,756	35,600	
4	FICA			5,019,886	5,019,886	
5						
6	MINNESOTA					
7	Property	9,898,581		9,726,947	9,726,840	
8	Income	-962,068		1,020,979	-962,068	
9	Unemployment	599		39,097	38,754	
10						
11	NORTH DAKOTA					
12	Property	2,900,002		1,542,327	1,455,272	
13	Income			1,078,762	1,078,762	
14	Unemployment	962		24,188	24,301	
15	Coal Conversion	160,714		2,184,051	2,156,402	
16						
17	SOUTH DAKOTA					
18	Property	2,101,419		2,159,950	1,842,282	
19	Unemployment	198		5,945	5,957	
20						
21	OTHER STATES					
22	Income					
23	Railcar	8,993		20,341	20,926	
24						
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41	TOTAL	14,109,924		36,803,285	31,870,829	

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
2,517,141		2,240,170			11,704,886	2
680					35,756	3
					5,019,886	4
						5
						6
9,898,688		9,726,947				7
1,020,979		594,995			425,984	8
942					39,097	9
						10
						11
2,987,057		1,506,136			36,192	12
		-71,801			1,150,563	13
849					24,188	14
188,363		2,184,051				15
						16
						17
2,419,087		2,159,950				18
186					5,945	19
						20
						21
						22
8,409					20,341	23
						24
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19,042,381		18,340,448			18,462,838	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) 12/31/2018	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

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

Account 409.2: 906,575 ; Other: 10,798,311

**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: 222,243 ; Other: 203,741

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

Account 184:

**Schedule Page: 262 Line No.: 12 Column: i**

Account 921: 28,344 ; Other: 7,848

**Schedule Page: 262 Line No.: 13 Column: i**

Account 409.2: 71,801 ; Other: 1,078,762

**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)  
12/31/2018

Year/Period of Report  
End of 2018/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%	21,232,526	190		411.4	1,306,824	
3	4%						
4	7%						
5	10%	146,225	411.4		411.4	98,268	
6							
7							
8	TOTAL	21,378,751				1,405,092	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
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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)  
12/31/2018

Year/Period of Report  
End of 2018/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
19,925,702			2
			3
			4
47,957			5
			6
			7
19,973,659			8
			9
			10
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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	1,076,026	456	329,755	524,650	1,270,921
2	Payroll Clearing	-118,595	184	33,762	63,409	-88,948
3	FCA Liability	5,778,436	173	5,823,543	165,729	120,622
4	Discontinued Mark-to-Market	2,404,638	182.3	1,627,868		776,770
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	9,140,505		7,814,928	753,788	2,079,365

**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	4,887,290	1,526,325	
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	4,887,290	1,526,325	
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)	4,887,290	1,526,325	
18	Classification of TOTAL			
19	Federal Income Tax	4,059,879	1,145,920	
20	State Income Tax	827,411	380,405	
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)

12/31/2018

Year/Period of Report

End of 2018/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
						6,413,615	4
							5
							6
							7
						6,413,615	8
							9
							10
							11
							12
							13
							14
							15
							16
						6,413,615	17
							18
						5,205,799	19
						1,207,816	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	186,474,995	11,428,215	9,999,134
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	186,474,995	11,428,215	9,999,134
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	186,474,995	11,428,215	9,999,134
10	Classification of TOTAL			
11	Federal Income Tax	140,620,518	7,721,405	7,035,493
12	State Income Tax	45,854,476	3,706,810	2,963,641
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
	92,155,254		673,565,182.3		2,627,707	189,766,063	2
							3
							4
	92,155		673,565		2,627,707	189,766,063	5
							6
							7
							8
	92,155		673,565		2,627,707	189,766,063	9
							10
	75,655		673,565		2,204,383	142,761,593	11
	16,499				423,324	47,004,470	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) 12/31/2018	2018/Q4
FOOTNOTE DATA			

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

Amortization of Loss on Reacquired Debt (pre-holdco)	(382,356)
Big Stone II Deferred Costs	(821,926)
Retirements Method Change	185,499
South Dakota Flow Thru-Overheads	(140)
Prepaid Expenses	(452,210)
ADR Repair Allowance	(1,924,126)
Sec 162 & 174 R&D Deduction	(3,496,603)
Highway Powerline Relocation	53,839
AFUDC on Debt	(3,490,634)
Capitalized Overheads	209,057
Repairs Deduction - Basis Adjustments	(11,896,434)
Sec 481(a) Cap to Repair Basis Adjustments (PY)	5,092,422
Legacy Tax Over Book Depreciation	(314,832,563)
North Dakota Investment Tax Credit - Federal Impacts	(6,925,758)
Legacy Accumulated Deferred Tax Due to Federal Rate Change	151,215,637
ASC 740 (SFAS 109) ADIT Credits - Property	(2,299,766)
	-----
	(189,766,062)
	=====

**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	9,977,208	4,834,713	2,677,353
5				
6	Accum. Deferred Income Tax			
7	Nonutility & Other	4,776,403		
8				
9	TOTAL Electric (Total of lines 3 thru 8)	14,753,611	4,834,713	2,677,353
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)	14,753,611	4,834,713	2,677,353
20	Classification of TOTAL			
21	Federal Income Tax	8,961,113	3,307,441	1,719,750
22	State Income Tax	5,792,498	1,527,272	957,603
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
	114,533			See Note	2,850,990	14,871,025	4
							5
							6
804,381	820,582	See Note	2,068,016			2,692,186	7
							8
804,381	935,115		2,068,016		2,850,990	17,563,211	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
804,381	935,115		2,068,016		2,850,990	17,563,211	19
							20
603,000	983,815				2,721,898	12,889,887	21
201,381	-48,700		2,068,016		129,093	4,673,325	22
							23

NOTES (Continued)

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) 12/31/2018	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

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

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.: 7 Column: g**

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

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

Pensions	(21,057,709)
Conservation Improvement Programs - MN & SD - Net (BTL)	(4,504,304)
Wind Rider Revenue	(297,062)
Transmission Rider Revenue	92,073
Environmental Rider Revenue	208,525
SPP Cost Tracker	20,974
EITE Revenue Tracker	(94,033)
ND Rate Case Expenses	(153,149)
MN Rate Case Expenses	(6,626)
SD Rate Case Expenses	(46,567)
Deferred State NOL's - Red Haircut	(614,847)
Regulatory Adjustments - JE 820 ESSRP	697,326
Excess Accumulated Deferred Tax due to Federal Rate Change	9,855,862
ASC 740 (SFAS 109) ADIT Credits - Non-Property	<u>(1,663,676)</u>
	<u>17,563,211</u>

**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	514,871	190	109,702	44,129	449,298
3	ADIT Legacy Reclass	148,537,638	See Note	14,328,929	8,121,145	142,329,854
4						
5	Minnesota Portion of Gain on Sale	89,220	407.4	5,576		83,644
6	of Wahpeton Division Office					
7						
8	Reclass SD EEP to Regulatory Liability					
9						
10	MN Transmission Revenue Rider	801,554	See Note	984,102	182,548	
11	ND Transmission Revenue Rider	349,015	See Note	1,056,445	767,837	60,407
12	SD Transmission Revenue Rider	151,306	See Note	275,475	292,058	167,889
13						
14	MN Future Rate Case Expense Accrual	207,560		207,571	166,297	166,286
15						
16	MN Environmental Revenue Rider	1,667,262	See Note	1,741,136	73,874	
17	ND Environmental Revenue Rider		See Note	478,394	478,394	
18	SD Environmental Revenue Rider	186,662	See Note	122,288	142,411	206,785
19						
20	MN Renewable Resource Rider	408,994	See Note	502,405	93,411	
21	ND Renewable Resource Rider		See Note	711,539	888,129	176,590
22						
23	MISO Schedule 26 and 26A Accrual	179,539	See Note	179,539	187,191	187,191
24						
25	SPP Cost Recovery Rider Refund	609,467	See Note	1,020,045	410,578	
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	<b>TOTAL</b>	153,703,088		21,723,146	11,848,002	143,827,944

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) 12/31/2018	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

<b>Schedule Page: 278 Line No.: 3 Column: c</b> Offsetting accounts were 182.3, 282, 283, and 190.
<b>Schedule Page: 278 Line No.: 10 Column: c</b> Offsetting accounts were 440, 442, 444, and 445.
<b>Schedule Page: 278 Line No.: 11 Column: c</b> Offsetting accounts were 440, 442, 444, and 445.
<b>Schedule Page: 278 Line No.: 12 Column: c</b> Offsetting accounts were 440, 442, 444, and 445.
<b>Schedule Page: 278 Line No.: 16 Column: c</b> Offsetting accounts were 440, 442, 444, and 445.
<b>Schedule Page: 278 Line No.: 17 Column: c</b> Offsetting accounts were 440, 442, 444, and 445.
<b>Schedule Page: 278 Line No.: 18 Column: c</b> Offsetting accounts were 440, 442, 444, and 445.
<b>Schedule Page: 278 Line No.: 20 Column: c</b> Offsetting accounts were 440, 442, 444, and 445.
<b>Schedule Page: 278 Line No.: 21 Column: c</b> Offsetting accounts were 440, 442, 444, and 445.
<b>Schedule Page: 278 Line No.: 23 Column: c</b> Offsetting accounts were 440, 442, 444, and 445.
<b>Schedule Page: 278 Line No.: 25 Column: c</b> 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	127,538,863	117,437,982
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	141,495,988	139,629,214
5	Large (or Ind.) (See Instr. 4)	121,820,577	113,218,700
6	(444) Public Street and Highway Lighting	3,924,126	3,769,175
7	(445) Other Sales to Public Authorities	3,286,993	3,104,146
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	398,066,547	377,159,217
11	(447) Sales for Resale	7,735,068	5,173,104
12	TOTAL Sales of Electricity	405,801,615	382,332,321
13	(Less) (449.1) Provision for Rate Refunds	12,950,014	4,982,931
14	TOTAL Revenues Net of Prov. for Refunds	392,851,601	377,349,390
15	Other Operating Revenues		
16	(450) Forfeited Discounts	733,490	708,000
17	(451) Miscellaneous Service Revenues	384,251	383,969
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	654,270	648,637
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	6,107,489	7,994,584
22	(456.1) Revenues from Transmission of Electricity of Others	45,204,517	43,474,731
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	53,084,017	53,209,921
27	TOTAL Electric Operating Revenues	445,935,618	430,559,311

**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
1,321,132	1,243,194	104,038	103,804	2
				3
1,607,370	1,568,284	27,110	26,991	4
1,983,281	1,938,423	13	58	5
24,753	24,995	397	404	6
40,424	40,088	592	595	7
				8
				9
4,976,960	4,814,984	132,150	131,852	10
312,412	225,607			11
5,289,372	5,040,591	132,150	131,852	12
				13
5,289,372	5,040,591	132,150	131,852	14

Line 12, column (b) includes \$ 1,170,228 of unbilled revenues.  
 Line 12, column (d) includes 10,001 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) 12/31/2018	Year/Period of Report 2018/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 customer having a demand exceeding 1000 kw.

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

Description of Revenue	Current Year	Prior Year
All Others	<u>384,251</u>	<u>383,969</u>
Total	<u><u>384,251</u></u>	<u><u>383,969</u></u>

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

Description of Revenue	Current Year	Prior Year
Sales of Steam	1,668,488	1,724,719
Integrated Transmission Deficiency Payments	(9,035)	1,419,043
Load Control & Dispatch	1,996,561	1,505,914
Wind Generation Development	303,868	0
Power Plan	0	411,587
Capital Equipment Tax Refund	0	464,863
All Others (under \$250,000 each)	<u>2,147,607</u>	<u>2,468,458</u>
Total	<u><u>6,107,489</u></u>	<u><u>7,994,584</u></u>

Name of Respondent  
Otter Tail Power Company

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

Date of Report  
(Mo, Da, Yr)  
12/31/2018

Year/Period of Report  
End of 2018/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					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential - 440					
2	Residential Service 9.01	915,903	99,448,037	98,850	9,266	0.1086
3						
4	Residential Service (Ctrl'd Demand					
5	9.02	150,168	12,431,754	6,134	24,481	0.0828
6						
7	Water Heating Ctrl'd (Off-Peak)					
8	14.01	35,354	2,915,051	15,335	2,305	0.0825
9						
10	Controlled Service					
11	14.04,14.05,14.06,14.07	203,678	10,942,842	13,743	14,820	0.0537
12						
13	Fixed Time of Delivery Service 14	6,821	271,216	444	15,363	0.0398
14						
15	Outdoor lighting-energy only 11.0	3,567	565,600	276	12,924	0.1586
16						
17	Outdoor Lighting 11.04	74	7,216	15	4,933	0.0975
18						
19	Small power producer rider 12.01		470	36		
20						
21	Off-peak Electric Vehicle Rider 1	18	899	10	1,800	0.0499
22						
23	LED Flood & Street and Area Light	36	20,281	9	4,000	0.5634
24						
25	Conservation Imp Program Revenue		-1,614,072			
26	Environmental Rider Revenue		332,864			
27	Transmission Cost Recovery Rider		-76,940			
28	Renewable Resource Rider Revenue		-59,882			
29	Fuel Clause Adjustment Receivable		1,508,802			
30	Southwest Power Pool Rider Revenu		187,912			
31	EITE Revenue Rider		75,894			
32	MN Rate Case		-33,754			
33	ND Interim Rate Refund		-16,663			
34	SUBTOTAL Billed	1,315,619	126,907,527	134,852	9,756	0.0965
35	Unbilled Rev (See Instr. 6)	5,512	631,335			0.1145
36	TOTAL - 440	1,321,131	127,538,862	134,852	9,797	0.0965
37						
38	Column D Lines 8,11,14,17,19&22					
39	customers are also served					
40	under other residential service.					
41	TOTAL Billed	4,966,959	383,946,304	172,893	28,729	0.0773
42	Total Unbilled Rev.(See Instr. 6)	10,001	1,170,228	0	0	0.1170
43	TOTAL	4,976,960	385,116,532	172,893	28,786	0.0774

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	779,822	79,189,548	25,216	30,926	0.1015
4						
5	Farm Service					
6	9.03	78,270	7,346,300	2,853	27,434	0.0939
7						
8	Large General Service					
9	10.03	572,035	42,343,923	359	1,593,412	0.0740
10						
11	Real Time Pricing Rider					
12	14.02	58,020	2,137,608	2	29,010,000	0.0368
13						
14	Large Gen. Srv. (Time of Day)					
15	10.05	1,133,367	67,055,285	100	11,333,670	0.0592
16						
17	Large General Service Rider					
18	14.03	149,916	4,705,244	15	9,994,400	0.0314
19						
20	Water Heating Ctrlld (Off-Peak)					
21	14.01	1,880	142,001	473	3,975	0.0755
22						
23	Controlled Service					
24	14.04,14.05,14.06,14.07	208,443	9,400,399	5,008	41,622	0.0451
25						
26	Fixed Time of Delivery Service					
27	14.07	26,445	993,417	594	44,520	0.0376
28						
29	Irrigation Service					
30	11.02	5,196	476,184	363	14,314	0.0916
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	4,966,959	383,946,304	172,893	28,729	0.0773
42	Total Unbilled Rev.(See Instr. 6)	10,001	1,170,228	0	0	0.1170
43	TOTAL	4,976,960	385,116,532	172,893	28,786	0.0774

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	557,093	43,550,350	578	963,829	0.0782
4						
5	Outdoor Lighting - Energy Only 11	2,007	184,033	270	7,433	0.0917
6						
7	Outdoor Lighting 11.04	13,396	1,939,354	235	57,004	0.1448
8						
9	Standby Service - Option A Firm 1	145	18,509	5	29,000	0.1276
10						
11	Small Power Producer Rider 12.01		711	35		
12						
13	LED Flood & Street and Area Light	217	94,799	7	31,000	0.4369
14						
15	Conservation Imp Prog Revenue		-2,911,451			
16	Environmental Rider Revenue		1,282,382			
17	Transmission Cost Recovery Rider		-146,164			
18	Renewable Resource Rider		301,130			
19	Fuel Clause Adjustment Receivable		4,042,269			
20	Southwest Power Pool Rider		589,499			
21	EITE Revenue Rider		174,436			
22	MN Rate Case		-130,705			
23	ND Interim Rate Refund		16,002			
24	SUBTOTAL Billed	3,586,252	262,795,063	36,113	99,306	0.0733
25	Unbilled Rev (See Instr. 6)	4,401	521,502			0.1185
26	TOTAL - 442	3,590,653	263,316,565	36,113	99,428	0.0733
27						
28						
29						
30	Column D Lines 6,9 & 15					
31	customers are also served under					
32	other commerical service.					
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	4,966,959	383,946,304	172,893	28,729	0.0773
42	Total Unbilled Rev.(See Instr. 6)	10,001	1,170,228	0	0	0.1170
43	TOTAL	4,976,960	385,116,532	172,893	28,786	0.0774

## 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	Streetlighting - 444					
2	Outdoor Lighting-Energy Only 11.0	6,301	542,461	294	21,432	0.0861
3						
4	Outdoor lighting 11.04	18,383	3,297,205	354	51,929	0.1794
5						
6	LED Flood & Street and Area Light	73	43,545	3	24,333	0.5965
7						
8	Conservation Imp Prog Revenue		-22,994			
9	Environmental Rider Revenue		5,784			
10	Transmission Cost Recovery Rider		-4,129			
11	Renewable Resource Rider		-142			
12	Fuel Clause Adjustment Receivable		52,223			
13	Southwest Power Pool Rider		2,740			
14	EITE Revenue Rider		813			
15	MN Rate Case		-663			
16	ND Interim Rate Refund		270			
17	Subtotal billed	24,757	3,917,113	651	38,029	0.1582
18	Unbilled Revenue	-5	7,012			-1.4024
19	TOTAL - 444	24,752	3,924,125	651	38,022	0.1585
20						
21	Other Public Authority-445					
22	Pumping and Sirens					
23	11.05,11.06	40,331	3,257,903	1,277	31,583	0.0808
24						
25	Outdoor Lighting - Energy Only 11		55	1		
26						
27	Conservation Imp Prog Revenue		-46,619			
28	Environmental Rider Revenue		11,889			
29	Transmission Cost Recovery Rider		-8,642			
30	Renewable Resource Rider		1,639			
31	Fuel Clause Adjustment Rec		54,521			
32	Southwest Power Pool Rider		5,527			
33	EITE Revenue Rider		1,115			
34	MN Rate Case		-1,164			
35	ND Interim Rate Refund		390			
36	Subtotal	40,331	3,276,614	1,278	31,558	0.0812
37	Unbilled Revenue	93	10,379			0.1116
38	TOTAL - 445	40,424	3,286,993	1,278	31,631	0.0813
39						
40	Revenue from Fuel Adjustment					
41	TOTAL Billed	4,966,959	383,946,304	172,893	28,729	0.0773
42	Total Unbilled Rev.(See Instr. 6)	10,001	1,170,228	0	0	0.1170
43	TOTAL	4,976,960	385,116,532	172,893	28,786	0.0774

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	Clause is reported in footnote.					
2						
3	Column D, Line 3					
4	customers are also served under					
5	other commercial service.					
6						
7	Provision for Rate Refunds FERC		-211,524			
8	Provision for Rate Refunds MN		-8,414,459			
9	Provision for Rate Refunds ND		-2,961,041			
10	Provision for Rate Refunds SD		-1,362,990			
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	4,966,959	383,946,304	172,893	28,729	0.0773
42	Total Unbilled Rev.(See Instr. 6)	10,001	1,170,228	0	0	0.1170
43	TOTAL	4,976,960	385,116,532	172,893	28,786	0.0774

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) 12/31/2018	2018/Q4
FOOTNOTE DATA			

**Schedule Page: 304 Line No.: 31 Column: a**

Energy Intensive Trade Exposed Revenue Rider

**Schedule Page: 304.2 Line No.: 21 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.: 33 Column: a**

Energy Intensive Trade Exposed Revenue Rider

**Schedule Page: 304.3 Line No.: 40 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	\$ 964,317
9.02	Residential service (control demand)	16,456
14.01	Water heating - controlled (off-peak)	64,239
14.04,14.05,14.06,14.07	Controlled service	38,901
14.07	Fixed time of delivery service	8,370
14.12	Off-Peak Electric Vehicle Rider	(28)
11.03	Outdoor lighting - energy only	3,576
11.04	Outdoor lighting	776
11.07	LED flood & street area lighting	(108)

Total residential \$ 1,096,499

Commercial and industrial - 442

10.01, 10.02	General service	\$ 695,147
9.03	Farm service	66,041
10.03	Large general service	(888,083)
14.02	Real time pricing rider	-
10.05	Large general service (time of day)	(1,728,494)
14.03	Large general service rider	(6,357)
14.01	Water heating - controlled (off-peak)	7,086
14.04,14.05,14.06,14.07	Controlled service	68,109
14.07	Fixed time of delivery service	15,368
11.02	Irrigation service	(4,355)
10.04	Commercial time of use	4,045,257
11.03	Outdoor lighting - energy only	1,097
11.04	Outdoor lighting	7,291
11.01	Standby service-option A firm	(233)
11.07	LED flood & street area lighting	(646)

Total commercial and industrial \$ 2,277,228

Streetlighting - 444

11.03	Outdoor lighting - energy only	\$ 22,036
11.04	Outdoor lighting	3,571
11.07	LED flood & street area lighting	(192)

Total streetlighting \$ 25,415

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) 12/31/2018	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Other public authority - 445

11.05,11.06	Pumping and sirens	\$ 37,032
11.03	Outdoor lighting - energy only	(1)

Total streetlighting	----- \$ 37,031
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Total	----- \$ 3,436,172 =====
-------	--------------------------------

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	.348	NA	NA
3	Newfolden, MN	RQ	174	.423	NA	NA
4	Nielsville, MN	RQ	175	.044	NA	NA
5	Shelly, MN	RQ	176	.181	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
	<b>Total</b>			<b>0</b>	<b>0</b>	<b>0</b>

SALES FOR RESALE (Account 447) (Continued)

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

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

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
					1
375	18,860	12,812	2,555	34,227	2
1,923	22,636	64,836	13,527	100,999	3
104	3,218	3,766	760	7,744	4
625	12,819	22,166	4,590	39,575	5
					6
					7
309,385		7,552,523		7,552,523	8
					9
					10
					11
					12
					13
					14
3,027	57,533	103,580	21,432	182,545	
309,385	0	7,552,523	0	7,552,523	
<b>312,412</b>	<b>57,533</b>	<b>7,656,103</b>	<b>21,432</b>	<b>7,735,068</b>	

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) 12/31/2018	Year/Period of Report 2018/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	<b>1. POWER PRODUCTION EXPENSES</b>		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,572,734	1,651,107
5	(501) Fuel	64,655,453	58,605,849
6	(502) Steam Expenses	6,351,768	5,817,946
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,734,180	2,441,793
10	(506) Miscellaneous Steam Power Expenses	5,898,230	5,061,938
11	(507) Rents	7,828	1,147
12	(509) Allowances	13,378	15,509
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	81,233,571	73,595,289
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	937,306	842,512
16	(511) Maintenance of Structures	989,059	1,202,457
17	(512) Maintenance of Boiler Plant	9,023,720	7,207,759
18	(513) Maintenance of Electric Plant	2,241,699	797,052
19	(514) Maintenance of Miscellaneous Steam Plant	1,010,467	1,063,182
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	14,202,251	11,112,962
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	95,435,822	84,708,251
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	25,372	13,178
45	(536) Water for Power		
46	(537) Hydraulic Expenses	13,832	11,472
47	(538) Electric Expenses	33,240	20,477
48	(539) Miscellaneous Hydraulic Power Generation Expenses	12,738	22,132
49	(540) Rents	-185	107
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	84,997	67,366
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	2,731	3,449
54	(542) Maintenance of Structures	12,239	5,016
55	(543) Maintenance of Reservoirs, Dams, and Waterways	221,684	277,356
56	(544) Maintenance of Electric Plant	907	50,242
57	(545) Maintenance of Miscellaneous Hydraulic Plant	38	
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	237,599	336,063
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	322,596	403,429

**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	291,679	265,030
63	(547) Fuel	2,675,963	1,484,624
64	(548) Generation Expenses	2,232,750	2,257,201
65	(549) Miscellaneous Other Power Generation Expenses	724,320	567,942
66	(550) Rents	605,389	593,392
67	TOTAL Operation (Enter Total of lines 62 thru 66)	6,530,101	5,168,189
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	71,670	85,285
70	(552) Maintenance of Structures	37,358	124,923
71	(553) Maintenance of Generating and Electric Plant	674,643	669,208
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	44,533	32,347
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	828,204	911,763
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	7,358,305	6,079,952
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	68,354,479	64,807,218
77	(556) System Control and Load Dispatching	334,921	590,724
78	(557) Other Expenses	44,769	50,392
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	68,734,169	65,448,334
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	171,850,892	156,639,966
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	367,684	419,482
84			
85	(561.1) Load Dispatch-Reliability	75,782	79,683
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,287,168	2,534,429
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	986,303	1,095,452
89	(561.5) Reliability, Planning and Standards Development	581,557	622,440
90	(561.6) Transmission Service Studies	534	5,175
91	(561.7) Generation Interconnection Studies	598	152
92	(561.8) Reliability, Planning and Standards Development Services	-2,347	10,000
93	(562) Station Expenses	335,296	297,518
94	(563) Overhead Lines Expenses	535,616	368,841
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	19,073,361	20,807,504
97	(566) Miscellaneous Transmission Expenses	771,179	619,124
98	(567) Rents	40,124	30,063
99	TOTAL Operation (Enter Total of lines 83 thru 98)	25,052,855	26,889,863
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	249,415	207,223
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	45,510	69,822
104	(569.2) Maintenance of Computer Software	560,943	716,648
105	(569.3) Maintenance of Communication Equipment	101,246	90,156
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,376,573	1,219,312
108	(571) Maintenance of Overhead Lines	2,017,323	1,936,496
109	(572) Maintenance of Underground Lines	5,272	14
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	4,356,282	4,239,671
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	29,409,137	31,129,534

**ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)**

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	<b>3. REGIONAL MARKET EXPENSES</b>		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation	771,704	712,690
117	(575.3) Transmission Rights Market Facilitation	2,772	2,097
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation	25,610	25,022
120	(575.6) Market Monitoring and Compliance	19,186	53,416
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	819,272	793,225
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software	280,206	212,635
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)	280,206	212,635
131	TOTAL Regional Transmission and Market Op Exps (Total 123 and 130)	1,099,478	1,005,860
132	<b>4. DISTRIBUTION EXPENSES</b>		
133	Operation		
134	(580) Operation Supervision and Engineering	347,829	279,039
135	(581) Load Dispatching	210,407	206,826
136	(582) Station Expenses	300,151	282,504
137	(583) Overhead Line Expenses	369,270	582,917
138	(584) Underground Line Expenses	1,960,970	1,943,453
139	(585) Street Lighting and Signal System Expenses	97	
140	(586) Meter Expenses	377,101	650,181
141	(587) Customer Installations Expenses	157,305	198,812
142	(588) Miscellaneous Expenses	4,039,352	3,661,715
143	(589) Rents	246,800	228,349
144	TOTAL Operation (Enter Total of lines 134 thru 143)	8,009,282	8,033,796
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	974,703	1,022,254
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	948,081	730,259
149	(593) Maintenance of Overhead Lines	5,100,397	4,884,313
150	(594) Maintenance of Underground Lines	992,980	1,016,562
151	(595) Maintenance of Line Transformers	106,774	93,253
152	(596) Maintenance of Street Lighting and Signal Systems	1,116,984	1,047,827
153	(597) Maintenance of Meters	872,528	800,588
154	(598) Maintenance of Miscellaneous Distribution Plant	146,099	132,993
155	TOTAL Maintenance (Total of lines 146 thru 154)	10,258,546	9,728,049
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	18,267,828	17,761,845
157	<b>5. CUSTOMER ACCOUNTS EXPENSES</b>		
158	Operation		
159	(901) Supervision	29,084	85,145
160	(902) Meter Reading Expenses	6,149,095	5,976,893
161	(903) Customer Records and Collection Expenses	5,275,143	5,579,346
162	(904) Uncollectible Accounts	1,135,000	750,000
163	(905) Miscellaneous Customer Accounts Expenses	546,737	520,483
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	13,135,059	12,911,867

**ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)**

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	<b>6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES</b>		
166	Operation		
167	(907) Supervision	429,220	603,596
168	(908) Customer Assistance Expenses	10,658,856	8,318,524
169	(909) Informational and Instructional Expenses	349,955	414,652
170	(910) Miscellaneous Customer Service and Informational Expenses	51,095	21,515
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	11,489,126	9,358,287
172	<b>7. SALES EXPENSES</b>		
173	Operation		
174	(911) Supervision	94,415	106,971
175	(912) Demonstrating and Selling Expenses	234,704	229,430
176	(913) Advertising Expenses	995	1,305
177	(916) Miscellaneous Sales Expenses	732	1,569
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	330,846	339,275
179	<b>8. ADMINISTRATIVE AND GENERAL EXPENSES</b>		
180	Operation		
181	(920) Administrative and General Salaries	24,231,985	23,839,398
182	(921) Office Supplies and Expenses	9,074,132	7,875,309
183	(Less) (922) Administrative Expenses Transferred-Credit	1,889,726	2,103,758
184	(923) Outside Services Employed	1,277,644	1,164,187
185	(924) Property Insurance	2,483,117	1,604,023
186	(925) Injuries and Damages	2,129,247	2,209,606
187	(926) Employee Pensions and Benefits	2,005,830	3,066,245
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	3,601,240	3,754,248
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	300,882	405,135
192	(930.2) Miscellaneous General Expenses	2,493,620	1,976,452
193	(931) Rents	246,258	281,269
194	TOTAL Operation (Enter Total of lines 181 thru 193)	45,954,229	44,072,114
195	Maintenance		
196	(935) Maintenance of General Plant	1,339,021	1,505,044
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	47,293,250	45,577,158
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	292,875,616	274,723,792

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) 12/31/2018	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

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

\$520,452 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**

\$607,221 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	Exelon Generation Company, LLC	SF		N/A	N/A	N/A
2	Great River Energy	SF		80	N/A	N/A
3	Great River Energy	SF		80	N/A	N/A
4	Minnesota Power	SF		20	N/A	N/A
5	Northern States Power Company	OS		N/A	N/A	N/A
6	Western Area Power Administration	EX		N/A	N/A	N/A
7	Western Area Power Administration WEC	OS		N/A	N/A	N/A
8	Beltrami Electric Cooperative	RQ		N/A	N/A	N/A
9	Nodak Rural Electric Cooperative	RQ		N/A	N/A	N/A
10	P K M Electric Cooperative	RQ		N/A	N/A	N/A
11	Red Lake Rural Electric Cooperative	RQ		N/A	N/A	N/A
12	Cass County Electric Cooperative	RQ		N/A	N/A	N/A
13	Whetstone Valley Electric Cooperative	RQ		N/A	N/A	N/A
14	Prairie Lakes Muni Waste	RQ		N/A	N/A	N/A
	<b>Total</b>					

**PURCHASED POWER (Account 555)**  
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Dakota Magic Casino	RQ		N/A	N/A	N/A
2	Kindred School	RQ		N/A	N/A	N/A
3	Stevens Community Medical	OS		N/A	N/A	N/A
4	City of Detroit Lakes	OS		N/A	N/A	N/A
5	American Crystal Sugar	OS		N/A	N/A	N/A
6	Hendricks Wind I	OS		N/A	N/A	N/A
7	Borderline Wind	OS		N/A	N/A	N/A
8	Univ. of MN - Morris	OS		N/A	N/A	N/A
9	FPL Energy ND II, LLC	OS		N/A	N/A	N/A
10	Langdon Wind, LLC	OS		N/A	N/A	N/A
11	Turtle Mountain Community College	OS		N/A	N/A	N/A
12	LacQui Parle School	OS		N/A	N/A	N/A
13	Pembina Border Station	OS		N/A	N/A	N/A
14	Lake Region State College	OS		N/A	N/A	N/A
	<b>Total</b>					

**PURCHASED POWER (Account 555)**  
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Ashtabula Wind III LLC	OS		N/A	N/A	N/A
2	Ashtabula Wind III LLC - Curtailment	OS		N/A	N/A	N/A
3	MN Co Generation	OS		N/A	N/A	N/A
4	ND Co Generation	OS		N/A	N/A	N/A
5	SD Co Generation	OS		N/A	N/A	N/A
6						
7						
8	Midwest ISO Energy Market	OS		N/A	N/A	N/A
9	Southwest Power Pool ISO Energy Market	OS		N/A	N/A	N/A
10						
11						
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)	
164,000				-836,678		-836,678	1
			1,178,750			1,178,750	2
			1,860,250			1,860,250	3
			190,000			190,000	4
204,000				2,880,466		2,880,466	5
-1,750				-47,712		-47,712	6
29,870				729,159		729,159	7
112,634			1,847,957	4,628,147	80,132	6,556,236	8
9,215			104,486	539,091		643,577	9
8,688			181,542	444,704		626,246	10
8,616			183,657	393,389		577,046	11
			7,102			7,102	12
			862			862	13
			7,040			7,040	14
2,339,598			5,628,344	62,646,006	80,132	68,354,482	

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)	
			10,800			10,800	1
			30,900			30,900	2
			23,760			23,760	3
1,027			1,238	1,541		2,779	4
37				367		367	5
1,492				38,093		38,093	6
1,160				34,799		34,799	7
4,562				250,913		250,913	8
47,417				1,417,767		1,417,767	9
69,318				2,718,660		2,718,660	10
231				6,501		6,501	11
1				14		14	12
951				25,062		25,062	13
4,491				140,757		140,757	14
2,339,598			5,628,344	62,646,006	80,132	68,354,482	

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)	
209,581				6,043,501		6,043,501	1
3,335				96,628		96,628	2
223				21,188		21,188	3
77				884		884	4
120				3,074		3,074	5
							6
							7
1,457,205				44,006,744		44,006,744	8
3,097				-891,053		-891,053	9
							10
							11
							12
							13
							14
2,339,598			5,628,344	62,646,006	80,132	68,354,482	

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) 12/31/2018	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

**Schedule Page: 326 Line No.: 1 Column: b**

January through May 2018

**Schedule Page: 326 Line No.: 2 Column: b**

June through December 2018.

**Schedule Page: 326 Line No.: 3 Column: b**

January through May 2018.

**Schedule Page: 326 Line No.: 4 Column: b**

June through December 2018

**Schedule Page: 326 Line No.: 8 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				
	<b>TOTAL</b>			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)  
(Including transactions referred to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
4	(1)	Badger, SD		1,557	1,490	1
4	(1)	Newfolden, MN		2,984	2,789	2
4	(1)	Nielsville, MN		658	615	3
4	(1)	Shelly, MN		2,048	1,914	4
4	(1)	Fort Totten, ND		333	314	5
4	(1)	Grafton, ND		4,700	4,434	6
4	(1)	Devils Lake, ND		470	439	7
4	(1)	Bottineau, ND		1,194	1,116	8
4	(1)	Wahpeton, ND		8,603	8,078	9
4	(1)	Belcourt, ND		2,319	2,188	10
4	(1)	Oakes, ND		70	67	11
See Footnote	(1)	Various Interconnect		241,867	226,044	12
		(1)		1,727		13
		(1)		-296,673		14
		(1)		-1,727		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	249,488	

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.
9,510			9,510	1
25,690			25,690	2
8,052			8,052	3
17,044			17,044	4
1,368			1,368	5
22,209			22,209	6
6,056			6,056	7
11,209			11,209	8
91,519			91,519	9
24,854			24,854	10
1,938			1,938	11
	221,016		221,016	12
				13
				14
				15
		44,764,053	44,764,053	16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
<b>219,449</b>	<b>221,016</b>	<b>44,764,053</b>	<b>45,204,518</b>	

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) 12/31/2018	Year/Period of Report 2018/Q4
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: n**

Midwest Independent System Operator Transmission

Schedule 1 Network = 194,593

Schedule 1 Firm = 39,240

Schedule 1 Non-firm = 7,462

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

Lines 1-10 Otter Tail Power Company wheels WAPA's portion of customer's 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 Contains 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	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	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					4,789,022	4,789,022
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL						4,789,022	4,789,022

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	254,496
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	286,458
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	200,681
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < \$5,000	48,294
6	Director Fees & Expenses	774,470
7	Misc Labor not Provided for Elsewhere	838,456
8	Press Release - Sundog Interactive, Inc	5,595
9	Membership Dues - Greater Minnesota Partnership	5,000
10	Membership Dues - Greater North Dakota Chmbr of Cmrc	5,000
11	Ethnographic Research & Social and Digital Monitorig	64,570
12	Strategy Workshop - Langlee Group, Inc	5,600
13	Sponsorship - Otter Tail Lakes Country Association	5,000
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	2,493,620

**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			2,060,999		2,060,999
2	Steam Production Plant	16,203,258	123,495			16,326,753
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	515,180				515,180
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	12,125,789	-3,619			12,122,170
7	Transmission Plant	8,785,818				8,785,818
8	Distribution Plant	11,511,131				11,511,131
9	Regional Transmission and Market Operation					
10	General Plant					
11	Common Plant-Electric	2,851,939				2,851,939
12	<b>TOTAL</b>	<b>51,993,115</b>	<b>119,876</b>	<b>2,060,999</b>		<b>54,173,990</b>

**B. Basis for Amortization Charges**

The \$2,060,999 Amortization of limited term Electric Plant is:

Franchise Consents (302):  
\$41,845 for hydo plant license with a remaining life of 3.92 years at a rate of 3.214%

Miscellaneous Intangible Plant (303):  
\$2,019,153 for computer software with a 5-year service life at a rate of 20.0%

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	61,990	34.24	-6.00	2.77	SQ	28.39
15	312	150,469	33.62	-6.00	3.06	SQ	28.39
16	314	11,953	43.02	-6.00	1.60	SQ	28.36
17	315	14,386	36.37	-6.00	2.51	SQ	28.39
18	316	1,626	41.14	-5.60	1.98	SQ	28.37
19							
20	Hoot Lake Plant						
21	311 - Units 2, 3	-135	36.76	-13.50	2.52	SQ	4.47
22	312 - Units 2, 3	6,650	14.59	-13.50	6.92	SQ	4.47
23	312.1 - Units 2, 3	7,522	38.09		2.18	SQ	32.99
24	314 - Units 2, 3	459	23.62	-13.50	3.91	SQ	4.47
25	315 - Units 2, 3	54	26.47	-13.50	3.45	SQ	4.47
26	316 - Units 2, 3	228	14.31	-13.40	7.27	SQ	4.47
27							
28	Coyote Plant						
29	311	9,427	50.61	-8.00	1.50	SQ	23.69
30	312	40,947	42.75	-8.00	2.01	SQ	23.71
31	314	10,835	38.41	-8.00	2.23	SQ	23.72
32	315	3,579	48.01	-8.00	1.61	SQ	23.70
33	316	1,183	36.58	-7.70	2.64	SQ	23.72
34							
35	STEAM PROD	321,173					
36							
37	Hydro Production-						
38	Hoot Lake Hydro						
39	331	1	61.30		0.23	SQ	4.47
40	332	28	29.94		2.09	SQ	4.47
41	333	7	36.16		1.42	SQ	4.47
42	334	3	30.74		1.96	SQ	4.47
43	335	24	8.92		11.13	SQ	4.47
44							
45	Wright Hydro						
46	331	3	30.74		2.96	SQ	4.47
47	332	400	9.59		10.02	SQ	4.47
48	333	90	9.30		3.71	SQ	4.47
49	334	49	17.81		5.40	SQ	4.47
50	335	41	12.21		8.05	SQ	4.47

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	Pisgah Hydro						
13	331	1	38.78		2.36	SQ	4.47
14	332	129	12.99		7.65	SQ	4.47
15	333	47	15.90		6.57	SQ	4.47
16	334	28	17.66		6.20	SQ	4.47
17	335	33	8.92		11.69	SQ	4.47
18							
19	Dayton Hallow						
20	331	8	9.95		10.34	SQ	4.47
21	332	583	10.69		10.10	SQ	4.47
22	333	66	14.18		6.48	SQ	4.47
23	334	39	21.36		4.51	SQ	4.47
24	335	54	8.94		10.77	SQ	4.47
25							
26	Taplin Gorge Hydro						
27	331	1	74.44		0.90	SQ	4.47
28	332	165	16.31		6.13	SQ	4.47
29	333	1	82.09		0.78	SQ	4.47
30	334	10	22.19		3.94	SQ	4.47
31	335	39	11.75		8.52	SQ	4.47
32							
33	Bemidji Hydro						
34	331	69	13.20		7.73	SQ	4.47
35	332	300	13.02		8.24	SQ	4.47
36	333	83	19.66		5.72	SQ	4.47
37	334	1	73.05		5.70	SQ	4.47
38	335		11.89		9.56	SQ	4.47
39							
40	HYDRO PROD	2,303					
41							
42	Other Production-						
43	Jamestown Peaking #1						
44	341	61	36.94	-1.60	1.45	SQ	16.14
45	342	152	28.20	-1.60	2.58	SQ	16.15
46	343	722	37.88	-1.60	1.58	SQ	16.14
47	345	33	55.72	-1.60	1.40	SQ	16.12
48	346	43	22.31	-1.60	3.20	SQ	16.15
49							
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	38	41.96	-2.80	1.19	SQ	16.13
14	342	64	39.92	-2.80	1.37	SQ	16.14
15	343	547	43.02	-2.80	1.21	SQ	16.13
16	345	71	41.94	-2.80	1.27	SQ	16.13
17	346	2	48.30	-2.80	0.65	SQ	16.13
18							
19	Jamestown Peaking #2						
20	341	10	27.52	-1.60	2.62	SQ	16.15
21	342	5	34.32	-1.60	1.01	SQ	16.12
22	343	654	43.13	-1.60	1.13	SQ	16.13
23	345	43	21.37	-1.60	3.77	SQ	16.15
24	346		45.46	-1.60	-0.46	SQ	16.13
25							
26	Fergus Falls Ctrl Ctr						
27	343	223	34.05		2.84	SQ	13.26
28							
29	Solway Combust Turbine						
30	341	2,600	33.01	-0.40	2.84	SQ	20.90
31	342	583	33.51	-0.40	2.80	SQ	20.90
32	343	12,906	33.08	-0.40	2.89	SQ	20.90
33	345	812	32.42	-0.40	2.99	SQ	20.90
34	346	221	31.06	-0.40	3.03	SQ	20.91
35							
36	Langdon Wind Enrgy Ctr						
37	341	1,494	24.33	-1.40	4.05	SQ	15.19
38	344	42,885	24.04	-1.40	4.17	SQ	15.19
39	345	4,542	23.84	-1.40	4.13	SQ	15.19
40	346	49	19.40	-1.40	5.03	SQ	15.20
41							
42	Ashtabula Wind Energy						
43	341	2,075	24.31	-1.20	4.03	SQ	16.15
44	344	69,961	24.12	-1.20	4.14	SQ	16.15
45	345	4,203	24.22	-1.20	4.09	SQ	16.15
46	346	22	20.47	-1.20	4.82	SQ	16.16
47							
48							
49							
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	Luverne Wind Energy						
13	341	1,519	24.29	-2.00	4.03	SQ	17.11
14	344	45,153	24.15	-2.00	4.13	SQ	17.11
15	345	3,262	24.28	-2.00	4.04	SQ	17.11
16	346	59	20.59	-2.00	4.78	SQ	17.11
17							
18	OTHER PROD	195,014					
19							
20	Transmission Plant						
21	350.1	13,415			1.43		70.00
22	353	100,752	65.14	-5.00	1.64	R1	53.63
23	354	100,564	70.00	-10.00	1.58	R5	65.34
24	355	65,872	70.37	-50.00	1.96	R2	54.21
25	356	98,453	70.23	-30.00	1.83	R2	55.11
26	358	4	42.48	-5.00	1.15	S4	8.92
27	SUBTOTAL	1,416,040					
28							
29	Distribution Plant						
30	362	58,315	40.64	5.00	2.11	SC	32.00
31	364	30,964	68.10	-75.00	2.49	R3	47.20
32	365	11,197	65.22	-100.00	2.82	R2.5	43.09
33	367	40,396	39.98	-5.00	2.36	R4	24.22
34	368	83,323	40.13	50.00	1.25	R2.5	28.05
35	369	-2,374	55.25	-150.00	4.18	S5	31.60
36	369.1	23,804	45.17	-20.00	2.57	R4	29.63
37	370	17,134	29.61		3.22	L0.5	20.73
38	370.1	730	12.63		5.30	R5	1.59
39	370.2		5.00		20.00	SQ-Amortized	
40	371.2	3,934	23.14	10.00	4.02	L0	17.03
41	373	2,743	22.56	-5.00	3.51	L0.5	15.13
42	SUBTOTAL	270,166					
43							
44	General Plant						
45	390	14,304	47.57	10.00	2.04	R1.5	30.07
46	390.1	3,560	32.85	49.60	0.69	SQ	13.26
47	390.2	420	27.32	33.60	1.33	SQ	8.41
48	390.3	2,397	49.66	92.60	-1.89	SQ	18.03
49							
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	General Plant (cont'd)						
13	391	363	15.00		6.67	SQ-Amortized	5.16
14	391.1	171	10.00		10.00	SQ-Amortized	2.47
15	391.2	111	10.00		10.00	SQ-Amortized	3.85
16	391.5	2,017	5.00		20.00	SQ-Amortized	2.15
17	391.6	364	5.00		20.00	SQ-Amortized	1.78
18	392	16,639					
19	Aircraft	648	7.00	25.00			
20	Autos		5.00	15.00			
21	Light Trucks		10.00	10.00			
22	Heavy Trucks & Semi		10.00	15.00			
23	Tractors (Includes		10.00	15.00			
24	Cranes)						
25	Trailers		15.00	10.00			
26	Portable Oil Purifier		10.00	20.00			
27	Trenchers		10.00	10.00			
28	Misc Light Equip		10.00	10.00			
29	Misc Heavy Equip		15.00	15.00			
30	394	2,255	15.00		6.67	SQ- Amortized	8.59
31	394.2	195	15.00		6.67	SQ- Amortized	5.84
32	395		15.00		6.67	SQ- Amortized	
33	396	460	25.59	20.00	3.03	L0	17.81
34	397	2,304	15.00		6.67	SQ-Amortized	8.03
35	397.1	376	10.00		10.00	SQ- Amortized	3.92
36	397.2	2,243	15.00		6.67	SQ- Amortized	7.92
37	397.3	262	10.00		10.00	SQ- Amortized	4.40
38	397.4	959	40.41	5.00	1.96	R3	23.32
39	SUBTOTAL	50,048					
40							
41	Total	1,736,254					
42							
43	SUBACCOUNTS USED						
44							
45							
46							
47							
48							
49							
50							

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

**Schedule Page: 336.4 Line No.: 43 Column: b**

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 Duplication 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) from 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	364,465		364,465	
3					
4	SD Public Utilities Commission	68,062		68,062	
5					
6	ND Public Service Commission	50		50	
7					
8	Federal Energy Regulatory Commission	639,983		639,983	
9					
10	Other Expenses:				
11	MN Public Utilities Commission:				
12	E017/CG-16-1021 (Red Lake Falls Comm Hybr		112,371	112,371	
13	E017/D-18-568 (2018 Depreciation Filing)		52,499	52,499	
14	E017/GR-15-1033 (MN Rate Case)		463,365	463,365	267,019
15	E017/M-17-257 (EITE Cust and EITE Cost Re		53,923	53,923	
16	E017/M-18-380 (Petition for Approval for		37,240	37,240	
17	Miscellaneous		217,361	217,361	
18					
19	ND Public Service Commission:				
20	PU-17-398 ND Rate Case		854,370	854,370	309,293
21	Miscellaneous		29,522	29,522	
22					
23	SD Public Utilities Commission:				
24	EL 18-021 (SD Rate Case)		556,113	556,113	
25	SD Gross Receipts Tax Assessment		49,585	49,585	
26	Miscellaneous		9,729	9,729	
27					
28	FERC				
29	Miscellaneous		92,602	92,602	
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	1,072,560	2,528,680	3,601,240	576,312

REGULATORY COMMISSION EXPENSES (Continued)

- 3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
- 4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
- 5. Minor items (less than \$25,000) may be grouped.

EXPENSES INCURRED DURING YEAR			AMORTIZED DURING YEAR				
CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Department (f)	Account No. (g)	Amount (h)					
							1
Electric	928	364,465					2
							3
Electric	928	68,062					4
							5
Electric	928	50					6
							7
Electric	928	639,983					8
							9
							10
							11
Electric	928	112,371					12
Electric	928	52,499					13
Electric	928	463,365			267,019		14
Electric	928	53,923					15
		37,240					16
		217,361					17
							18
							19
Electric	928	854,370	300,390		154,723	454,960	20
Electric	928	29,522					21
							22
							23
Electric	928	556,113	217,318		39,427	177,891	24
Electric	928	49,585					25
Electric	928	9,729					26
							27
							28
		92,602					29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		3,601,240	517,708		461,169	632,851	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		Fredrikson & Bryon PA
12		Microbeam Technologies 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
15,962		920.0	15,962		4
124		930.2	124		5
					6
					7
16,086			16,086		8
					9
					10
	1,845	506.0	1,845		11
	3,500	506.0	3,500		12
	6,750	930.2	6,750		13
					14
					15
	12,095		12,095		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					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)	73,621,301		73,621,301
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	20,147,207		20,147,207
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	20,147,207		20,147,207
72	Plant Removal (By Utility Departments)			
73	Electric Plant	346,334		346,334
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	346,334		346,334
77	Other Accounts (Specify, provide details in footnote):			
78	Fuel Stock (151)	59,010		59,010
79	Miscellaneous Deferred Debits (186)	1,288,575		1,288,575
80	Other Electric Revenue (456)	263,986		263,986
81	Expenses of Nonutility Operations (417.1)	105,608		105,608
82	Exp. for Certain Civic, Political and Related Activities (426)	125,782		125,782
83	Other Deductions (426.5)	208,523		208,523
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	2,051,484		2,051,484
96	TOTAL SALARIES AND WAGES	96,166,326		96,166,326

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) 12/31/2018	Year/Period of Report 2018/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) 12/31/2018	Year/Period of Report End of <u>2018/Q4</u>
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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.

Not Applicable

Name of Respondent  
Otter Tail Power Company

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

Date of Report  
(Mo, Da, Yr)  
12/31/2018

Year/Period of Report  
End of 2018/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					
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22					
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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)  
12/31/2018

Year/Period of Report  
End of 2018/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	912	16	9	911	1				
2	February	896	12	9	895	1				
3	March	763	13	9	762	1				
4	Total for Quarter 1				2,568	3				
5	April	766	6	8	765	1				
6	May	656	25	14	655	1				
7	June	732	28	16	731	1				
8	Total for Quarter 2				2,151	3				
9	July	719	11	15	718	1				
10	August	675	8	16	674	1				
11	September	604	10	16	603	1				
12	Total for Quarter 3				1,995	3				
13	October	693	12	9	692	1				
14	November	785	26	11	784	1				
15	December	818	31	18	817	1				
16	Total for Quarter 4				2,293	3				
17	Total Year to Date/Year				9,007	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) 12/31/2018	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

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

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

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

The peak numbers for November and 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)

12/31/2018

Year/Period of Report

End of 2018/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)	4,976,960
3	Steam	2,972,033	23	Requirements Sales for Resale (See instruction 4, page 311.)	3,027
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	309,385
5	Hydro-Conventional	21,971	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	12,648
7	Other	542,437	27	Total Energy Losses	294,661
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	5,596,681
9	Net Generation (Enter Total of lines 3 through 8)	3,536,441			
10	Purchases	2,339,598			
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	249,488			
18	Net Transmission for Other (Line 16 minus line 17)	-279,358			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	5,596,681			

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) 12/31/2018	Year/Period of Report End of <u>2018/Q4</u>
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**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	524,542	12,363	912	16	900
30	February	505,806	13,294	896	12	900
31	March	562,383	14,525	763	13	900
32	April	410,546	19,432	766	6	800
33	May	462,743	45,919	656	25	1400
34	June	398,035	41,549	732	28	1600
35	July	371,580	32,151	719	11	1500
36	August	408,661	32,227	675	8	1600
37	September	381,325	48,581	604	10	1600
38	October	502,384	15,978	693	12	900
39	November	573,637	19,332	785	26	1100
40	December	495,039	14,034	818	31	1800
41	TOTAL	5,596,681	309,385			

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) 12/31/2018	Year/Period of Report 2018/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)	152	257				
7	Plant Hours Connected to Load	7854	6728				
8	Net Continuous Plant Capability (Megawatts)	151	256				
9	When Not Limited by Condenser Water	151	256				
10	When Limited by Condenser Water	151	256				
11	Average Number of Employees	80	82				
12	Net Generation, Exclusive of Plant Use - KWh	1080638618	1367621148				
13	Cost of Plant: Land and Land Rights	713587	374603				
14	Structures and Improvements	34292524	79607321				
15	Equipment Costs	141329320	253584042				
16	Asset Retirement Costs	1377063	896678				
17	Total Cost	177712494	334462644				
18	Cost per KW of Installed Capacity (line 17/5) Including	1226.4492	1498.8243				
19	Production Expenses: Oper, Supv, & Engr	672858	689363				
20	Fuel	22354695	25674366				
21	Coolants and Water (Nuclear Plants Only)	0	0				
22	Steam Expenses	2259379	2596358				
23	Steam From Other Sources	0	0				
24	Steam Transferred (Cr)	0	0				
25	Electric Expenses	716082	855554				
26	Misc Steam (or Nuclear) Power Expenses	1625798	2372434				
27	Rents	7828	0				
28	Allowances	0	0				
29	Maintenance Supervision and Engineering	287420	419020				
30	Maintenance of Structures	293163	450006				
31	Maintenance of Boiler (or reactor) Plant	2721629	4631798				
32	Maintenance of Electric Plant	228267	1844279				
33	Maintenance of Misc Steam (or Nuclear) Plant	384303	338473				
34	Total Production Expenses	31551422	39871651				
35	Expenses per Net KWh	0.0292	0.0292				
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	879945	6869	0	850025	3747	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	6964	140000	0	8238	140000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	245652.000	92484.000	0.000	30.771	103.030	0.000
41	Average Cost of Fuel per Unit Burned	24.777	91.350	0.000	31.968	91.220	0.000
42	Average Cost of Fuel Burned per Million BTU	1.779	15.536	0.000	1.940	15.514	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.021	0.000	0.000	0.019	0.000	0.000
44	Average BTU per KWh Net Generation	11412.000	0.000	0.000	10490.000	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	1885	0				
8	Net Continuous Plant Capability (Megawatts)	43	0				
9	When Not Limited by Condenser Water	43	0				
10	When Limited by Condenser Water	43	0				
11	Average Number of Employees	2	0				
12	Net Generation, Exclusive of Plant Use - KWh	69282027	0				
13	Cost of Plant: Land and Land Rights	89809	0				
14	Structures and Improvements	4791410	0				
15	Equipment Costs	25193618	0				
16	Asset Retirement Costs	0	0				
17	Total Cost	30074837	0				
18	Cost per KW of Installed Capacity (line 17/5) Including	675.8390	0				
19	Production Expenses: Oper, Supv, & Engr	0	0				
20	Fuel	2337733	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	431216	0				
26	Misc Steam (or Nuclear) Power Expenses	248266	0				
27	Rents	129	0				
28	Allowances	0	0				
29	Maintenance Supervision and Engineering	13115	0				
30	Maintenance of Structures	32516	0				
31	Maintenance of Boiler (or reactor) Plant	0	0				
32	Maintenance of Electric Plant	403011	0				
33	Maintenance of Misc Steam (or Nuclear) Plant	6772	0				
34	Total Production Expenses	3472758	0				
35	Expenses per Net KWh	0.0501	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	707025	67	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	706114	140000	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.300	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	3.298	94.500	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.298	16.071	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.034	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	10211.000	0.000	0.000	0.000	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: (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
	145			43			20		6
	10937			42			54		7
	141			43			20		8
	141			43			20		9
	141			43			20		10
	34			1			0		11
	523772900			216018			495677		12
	565967			24614			12339		13
	6093767			311512			233982		14
	63745047			7684747			4033048		15
	484409			0			0		16
	70889190			8020873			4279369		17
	551.6668			166.7195			177.5672		18
	166572			0			356		19
	14681070			156201			182029		20
	0			0			0		21
	1393100			0			0		22
	0			0			0		23
	0			0			0		24
	1190601			49566			34271		25
	1133847			1352			185		26
	0			0			0		27
	13378			0			0		28
	248353			38760			15517		29
	247907			4077			864		30
	1655618			0			0		31
	171619			155932			50245		32
	253366			2505			0		33
	21155431			408393			283467		34
	0.0404			1.8906			0.5719		35
Coal	Oil		Oil			Oil			36
Tons	Barrels		Barrels			Barrels			37
330153	3747	0	1228	0	0	1877	0	0	38
9134	140000	0	140000	0	0	140000	0	0	39
40.846	97.520	0.000	100.254	0.000	0.000	104.870	0.000	0.000	40
42.281	97.310	0.000	127.260	0.000	0.000	96.980	0.000	0.000	41
2.314	16.549	0.000	21.643	0.000	0.000	16.493	0.000	0.000	42
0.028	0.000	0.000	0.723	0.000	0.000	0.367	0.000	0.000	43
11651.000	0.000	0.000	33431.000	0.000	0.000	22266.000	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)  
12/31/2018

Year/Period of Report  
End of 2018/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

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

Date of Report  
(Mo, Da, Yr)  
12/31/2018

Year/Period of Report  
End of 2018/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	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/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:  
(1)  An Original  
(2)  A Resubmission

Date of Report  
(Mo, Da, Yr)  
12/31/2018

Year/Period of Report  
End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

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



PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.

7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: <span style="float: right;">(c)</span>	0 FERC Licensed Project No. Plant Name: <span style="float: right;">(d)</span>	0 FERC Licensed Project No. Plant Name: <span style="float: right;">(e)</span>	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	4,555	661,464
3	Wright	1922	0.40	0.5	2,944	1,778,450
4	Pisgah	1917	0.65	0.8	4,369	714,887
5	Dayton Hollow	1909	0.97	1.0	5,546	1,864,753
6	Taplin Gorge	1925	0.56	0.3	3,921	958,938
7	Bemidji	1941	0.62	0.4	367	1,356,162
8						
9	Internal Combustion:					
10	Fergus Falls Control Center	1995	1.83	2.0	21	591,638
11	Diesel Generators		2.26			
12						
13	Wind Turbine Plants					
14	Langdon	2007	40.50	40.4	143,039	79,357,464
15	Ashtabula	2008	48.00	48.2	151,822	116,489,001
16	Luverne	2009	49.50	50.0	177,561	73,146,590
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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
869,204	6,790		32,629	-		2
3,542,730	6,232		35,641	-		3
953,182	6,549		56,530	-		4
1,781,044	5,326		49,342	-		5
3,512,594	5,475		37,679	-		6
3,513,374	5,105		25,778	-		7
						8
						9
289,593	2,018		7,893	Oil		10
				Oil		11
						12
						13
1,963,467	817,654		26,320			14
2,415,682	708,597		25,999			15
1,461,697	741,220		19,161			16
						17
						18
						19
						20
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						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) 12/31/2018	Year/Period of Report 2018/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	Center	Maple River	345.00	345.00	Alum Tower	59.00		1
2	Alexandria	MN Border	345.00	345.00	Steel Tower	101.00		1
3	Big Stone South	Brookings	345.00	345.00	Steel Tower	72.00		1
4	Brookings	MN Border	345.00	345.00	Steel Tower	10.00		1
5	Cedar Mountain	Helena	345.00	345.00	Steel Tower	73.00		2
6	Cedar Mountain	Lyon County	345.00	345.00	Steel Tower	49.00		2
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	2.00		1
33	Big Stone Plant	Big Stone South	230.00	230.00	Steel Tower	2.00		1
34		Total	115.00	115.00	Wood H	455.00		
35		Total	115.00	115.00	SWP	414.00		
36					TOTAL	5,963.00		34

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	115.00	115.00	Steel Tower	4.00		
2		Total	69.00	69.00		215.00		
3		Total	41.60	41.60	SWP	3,774.00		
4		Total	41.60	41.60	Underground	1.00		
5								
6								
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9								
10								
11								
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28								
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31								
32								
33								
34								
35								
36					TOTAL	5,963.00		34

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)	
		5,458,744	5,458,744					1
	2,908,447	30,054,193	32,962,640					2
	3,608,704	49,626,262	53,234,966					3
	93,013	1,046,914	1,139,927					4
	1,365,905	6,388,228	7,754,133					5
	483,093	3,984,308	4,467,401					6
	491,533	2,427,110	2,918,643					7
	869,812	2,154,448	3,024,260					8
	154,740	2,002,725	2,157,465					9
	129,317	3,735,690	3,865,007					10
	616,125	8,167,232	8,783,357					11
	2,259,131	8,201,392	10,460,523					12
	2,680,036	23,297,499	25,977,535					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
		1,688,877	1,688,877					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	4,363,752	4,853,484					29
	567,060	10,910,711	11,477,771					30
	47,522	704,213	751,735					31
	53,811	1,022,410	1,076,221					32
	58,249	1,106,691	1,164,940					33
	13,776	13,908,530	13,922,306					34
	1,087,764	30,422,846	31,510,610					35
	18,048,938	369,129,103	387,178,041	5,581,946	2,132,823	40,124	7,754,893	36

Name of Respondent  
Otter Tail Power Company

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

Date of Report  
(Mo, Da, Yr)  
12/31/2018

Year/Period of Report  
End of 2018/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)	
	15,567	187,032	202,599					1
	53,441	7,969,092	8,022,533					2
		114,821,388	114,821,388					3
		77,461	77,461					4
				5,581,946	2,132,823	40,124	7,754,893	5
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	18,048,938	369,129,103	387,178,041	5,581,946	2,132,823	40,124	7,754,893	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) 12/31/2018	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

**Schedule Page: 422.1 Line No.: 5 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	Not Applicable						
2							
3							
4							
5							
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9							
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42							
43							
44	TOTAL						

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)	
									1
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**SUBSTATIONS**

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation  (a)	Character of Substation  (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	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	115.00	43.80	
38	Wahpeton Inventory	Transmission	345.00	115.00	43.00
39	WAPA Summit, ND	Transmission	115.00	41.60	
40	Winger, MN 63238	Transmission	230.00	115.00	13.20

**SUBSTATIONS**

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation  (a)	Character of Substation  (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Subtotal:		6670.00	2807.20	496.90
2					
3	Transmission Subs Under 10,000 kva				
4	Colgate	Transmission	69.00	43.80	12.50
5	Green Valley	Transmission	67.00	41.60	
6	Lake Preston	Transmission	69.00	44.00	
7	St Vincent	Transmission	69.00	41.60	
8	Wahpeton Inventory	Transmission	69.00	41.60	
9	Total:		7013.00	3019.80	509.40
10					
11	Distribution Subs 10,000 kva or higher				
12	Bemidji, MN 25th Street	Distribution	69.00	12.50	
13	Bemidji, MN Airport	Distribution	41.60	12.50	
14	Bemidji, MN Nymore	Distribution	69.00	12.50	
15	Bemidji, MN Industrial Park	Distribution	69.00	12.50	
16	Bottineau, ND Downtown	Distribution	41.60	12.50	
17	Casselton, ND	Distribution	41.60	12.50	
18	Casselton, ND Ethanol plant	Distribution	115.00	12.50	
19	Cass Lake, MN	Distribution	115.00	12.50	
20	Clearbrook, MN Pipeline	Distribution	115.00	4.16	
21	Cooperstown, ND	Distribution	41.60	12.50	
22	Crookston, MN Parkview	Distribution	41.60	12.50	
23	Crookston, MN South Main	Distribution	41.60	12.50	
24	Dawson, MN Dawson Mills	Distribution	115.00	12.50	
25	Devils Lake, ND Downtown	Distribution	41.60	4.16	
26	Enderlin, ND	Distribution	115.00	12.50	
27	Fairmount, ND	Distribution	115.00	12.50	
28	Fergus Falls, MN Edgetown	Distribution	115.00	12.50	
29	Fergus Falls, MN Hoot Lake	Distribution	115.00	12.50	
30	Fergus Falls, MN South East	Distribution	115.00	12.50	
31	Gwinner, ND	Distribution	115.00	12.50	
32	Harvey, ND Northwest	Distribution	115.00	12.50	
33	Itasca, MN Minnesota Pipeline	Distribution	115.00	4.16	
34	Jamestown, ND Downtown	Distribution	115.00	12.50	
35	Jamestown, ND North	Distribution	115.00	12.50	
36	Jamestown, ND Potato	Distribution	115.00	12.50	
37	Jamestown, ND Southwest	Distribution	41.60	12.50	
38	Lake Norden, SD Dairy	Distribution	41.60	12.50	
39	Lake Norden, SD Dairy	Distribution	115.00	12.50	
40	Lisbon, ND Town	Distribution	115.00	12.50	

**SUBSTATIONS**

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation  (a)	Character of Substation  (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Mahnomen, MN	Distribution	115.00	12.50	
2	Mapleton, MN	Distribution	115.00	12.50	
3	Milbank, SD Northwest	Distribution	41.60	12.50	
4	Milbank, SD South	Distribution	41.60	12.50	
5	Morris, MN Northeast	Distribution	41.60	12.50	
6	Morris, MN South	Distribution	115.00	12.50	
7	Oakes, ND North	Distribution	41.60	12.50	
8	Parkers Prairie	Distribution	41.60	12.50	
9	Pelican Rapids, MN Turkey Plant	Distribution	115.00	12.50	
10	Perham, MN	Distribution	115.00	12.50	
11	Rosholt, SD	Distribution	41.60	12.50	
12	Rugby, ND South	Distribution	41.60	12.50	
13	Spiritwood, ND	Distribution	115.00	12.50	
14	Wahpeton Inventory	Distribution	115.00	12.50	
15	Wahpeton Inventory	Distribution	115.00	4.16	
16	Wahpeton Inventory	Distribution	41.60	12.50	
17	Wahpeton Inventory	Distribution	41.60	4.16	
18	Wahpeton, ND North 115 kv - 63230	Distribution	115.00	12.50	
19	Wahpeton, ND Northwest	Distribution	41.60	12.50	
20	Wheaton, MN South	Distribution	115.00	12.50	
21	Distribution Subtotal:		4102.40	570.80	
22					
23	Distribution Under 10,000 kva	Distribution			
24	Distribution Total		4102.40	570.80	
25	Transmission From Above		6898.00	2976.00	510.00
26	Transmission & Distribution		10655.40	3509.30	510.00
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
		2				37
		1				38
25	1					39
140	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)	
4203	43	4				1
						2
						3
6	1					4
7	1					5
9	1					6
8	1					7
		1				8
4233	47	5				9
						10
						11
20	1					12
14	1					13
14	1					14
11	1					15
10	3					16
10	1					17
94	2					18
14	1					19
28	2					20
10	1					21
10	1					22
39	2					23
10	1					24
10	1					25
14	1					26
10	3					27
37	1					28
37	1					29
37	1					30
20	2					31
14	1					32
11	1					33
14	1					34
14	1					35
14	1					36
14	1					37
12	1					38
41	1					39
14	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)	
14	1					1
14	1					2
22	1					3
22	1					4
12	1					5
12	3					6
10	3					7
10	1					8
10	1					9
28	2					10
10	1					11
10	1					12
56	2					13
		1				14
		1				15
		1				16
		1				17
24	2					18
20	2					19
12	1					20
883	61	4				21
						22
						23
883	61	4				24
4233	47	3				25
5075	105	9				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) 12/31/2018	Year/Period of Report 2018/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)
<b>1</b>	<b>Non-power Goods or Services Provided by Affiliated</b>			
2	Construction work in progress	Otter Tail Corporation	107	15,563
3	Expenditures for certain civic, political & relat	Otter Tail Corporation	426.4	25,666
4	Dividends declared - common stock	Otter Tail Corporation	438	42,506,846
5	Corporate allocated A&G expense	Otter Tail Corporation	See Note	11,407,868
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
<b>20</b>	<b>Non-power Goods or Services Provided for Affiliate</b>			
21	Printing, design & mailing services	Otter Tail Corporation	417	28,823
22	Other deductions	Otter Tail Corporation	426.5	475,662
23				
24	Printing, design & mailing services	BTD Manufacturing	417	16,731
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
<b>1</b>	<b>Non-power Goods or Services Provided by Affiliated</b>			
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	<b>Non-power Goods or Services Provided for Affiliate</b>			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

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) 12/31/2018	2018/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	\$	8,036.43
506		3,627.04
561.2		309.79
588		1,304.99
593		30.00
908		2,923.76
912		12,500.76
921		3,247,726.01
924		9,718.25
926		1,064.29
928		9,548.72
930.2		1,135,449.66
935		317,929.24
920		5,207,535.03
923		1,120,671.91
925		177,884.22
930.1		7,167.46
931		144,440.81
Total		11,407,868

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