

THIS FILING IS

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

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2016)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2016)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2016)



FERC FINANCIAL REPORT

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

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

Exact Legal Name of Respondent (Company)

Otter Tail Power Company

Year/Period of Report

End of 2014/Q4


**FERC FORM NO. 1/3-Q:
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 2014/Q4	
03 Previous Name and Date of Change (if name changed during year) / /		
04 Address of Principal Office at End of Period (Street, City, State, Zip Code) 215 South Cascade Street, PO Box 496, Fergus Falls, MN 56538-0496		
05 Name of Contact Person Jeff Legge	06 Title of Contact Person Controller, Utility	
07 Address of Contact Person (Street, City, State, Zip Code) PO Box 496, Fergus Falls, MN 56538-0496		
08 Telephone of Contact Person, including Area Code (218) 739-8291	09 This Report Is (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	10 Date of Report (Mo, Da, Yr) 12/31/2014

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name George Bell	03 Signature  George Bell	04 Date Signed (Mo, Da, Yr) 04/06/2015
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.

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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	

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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)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	Not applicable
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	

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

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GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

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

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

Minnesota - July 5, 1907

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

Not Applicable

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

Minnesota - Electric
North Dakota - Electric
South Dakota - Electric

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

- (1) Yes...Enter the date when such independent accountant was initially engaged:
(2) No

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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.

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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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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 [1]	Charles S. MacFarlane	
2			
3	Vice President, IT and Special Projects	Rodney C.H. Scheel	
4			
5	Vice President, Customer Service	Mark H. Helland	
6			
7	Vice President, Administration	Thomas R. Brause	
8			
9	Chief Financial Officer	George D. Bell	
10			
11	Vice President, Energy Supply	Jan P. Rudolf	
12			
13	President, Utility [2]	Timothy J. Rogelstad	
14			
15	General Counsel & Secretary	Jennifer O. Smestad	
16			
17	Vice President, Asset Management [3]	JoAnn M. Thompson	
18			
19	Vice President, Public Relations	Cris M. Oehler	
20			
21	Vice President, Planning and Strategy [3]	Bradley E. Tollerson	
22			
23	Treasurer * **	Kevin G. Moug	
24			
25	Assistant Secretary * **	George A. Koeck	
26			
27	Assistant Treasurer * **	Brian Carlson	
28			
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32			
33	[1] Effective 04/14/2014 became Otter Tail Corporation employee. Salary above reflects 1/1/2014 - 4/13/2014 time period as an officer of Otter Tail Power Company.		
34			
35			
36			
37	[2] Effective 04/14/2014 became President, Utility.		
38	[3] Effective 06/01/2014.		
39			
40	* This individual is an employee of Otter Tail Corporation.		
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42			
43	** Portion of salary allocated to the Utility.		
44			

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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	Edward J. McIntyre, Director	Fargo, North Dakota
3		
4	George A. Koeck, Director, Assistant Secretary	Fargo, North Dakota
5		
6	Charles S. MacFarlane, Director, and CEO, Utility	Fergus Falls, Minnesota
7		
8	Kevin Moug, Director, Treasurer	Fargo, North Dakota
9		
10	Shane Waslaski, Director [2]	Fargo, North Dakota
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12	Timothy J. Rogelstad, Director [1]	Fergus Falls, Minnesota
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45	[1] Effective 04/14/2014.	
46	[2] Removed effective 05/15/2014.	
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INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

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

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	E13-674-000;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
29	MISO FERC Electric Tariff	ER13-2379-000;003
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
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INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No
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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
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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
1	NA	See specific footnote accompanying each applicable		NA NA
2		Form 1 Schedule.		
3				
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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.

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Otter Tail Power Company			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

1. None.
2. None.
3. None.
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-14-381 dated July 21, 2014.
7. None.
8. The average annual increase for full-time nonunion employees was 3.01% effective April 1, 2014. Wages for Local Union 1570 were increased by 3.0% effective September 1, 2014. Wages for Local Unions 203, 239, 524, and 949 were increased by 3.0% effective November 1, 2014.
9. None.
10. Otter Tail Power Company is a subsidiary of Otter Tail Corporation.
11. (Reserved.)
12. None.
13. Cris Oehler, Vice President, Public Relations effective January 1, 2014; Charles MacFarlane, Chief Executive Officer, Utility effective April 14, 2014; Timothy J. Rogelstad, President, Utility effective April 14, 2014; Shane Waslaski was removed as director effective May 15, 2014; JoAnn Thompson, Vice President, Asset Management effective June 1, 2014; Bradley Tollerson, Vice President, Planning and Strategy effective June 1, 2014.
14. Not applicable.

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COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200-201	1,545,112,170	1,460,884,231
3	Construction Work in Progress (107)	200-201	240,169,972	184,779,895
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		1,785,282,142	1,645,664,126
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	659,193,694	626,272,583
6	Net Utility Plant (Enter Total of line 4 less 5)		1,126,088,448	1,019,391,543
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)		1,126,088,448	1,019,391,543
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		429,511	250,911
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)		195,977	238,419
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		840,135	1,670,542
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)		1,465,623	2,159,872
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		10,300	10,300
36	Special Deposits (132-134)		2,749,931	3,508,580
37	Working Fund (135)		19,055	19,055
38	Temporary Cash Investments (136)		148,179	0
39	Notes Receivable (141)		50,000	0
40	Customer Accounts Receivable (142)		19,737,127	20,298,320
41	Other Accounts Receivable (143)		12,534,153	9,197,337
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		824,670	888,740
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		44,859	11,132
45	Fuel Stock (151)	227	9,624,428	9,036,445
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	18,423,124	17,673,569
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	0	0

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) 12/31/2014	Year/Period of Report End of <u>2014/Q4</u>
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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)		426,614	398,997
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)		19,110,252	18,685,179
62	Miscellaneous Current and Accrued Assets (174)		21,586	90,919
63	Derivative Instrument Assets (175)		257,105	337,791
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		4	62,363
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		82,332,047	78,441,247
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		3,079,532	2,798,777
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	4,642,624	5,843,886
72	Other Regulatory Assets (182.3)	232	147,143,701	92,474,648
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)		-27,466	147,263
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	144,583	165,165
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)		2,241,075	2,592,053
82	Accumulated Deferred Income Taxes (190)	234	107,452,075	108,426,748
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		264,676,124	212,448,540
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		1,474,562,242	1,312,441,202

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) 12/31/2014	2014/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, 2013	398,997
January 31, 2014	1,601,267
February 28, 2014	1,324,422
March 31, 2014	1,119,737
April 30, 2014	2,390,269
May 31, 2014	2,129,670
June 30, 2014	1,899,910
July 31, 2014	1,640,283
August 31, 2014	1,380,656
September 30, 2014	1,153,269
October 31, 2014	892,240
November 30, 2014	632,640
December 31, 2014	426,614
13-month average for rate-making	1,306,921

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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) 12/31/2014	Year/Period of Report end of 2014/Q4
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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	296,261,391	252,261,391
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	147,114,517	138,838,672
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)	-1,853,222	-1,160,288
16	Total Proprietary Capital (lines 2 through 15)		441,523,186	389,940,275
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	445,000,000	335,900,000
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)		445,000,000	335,900,000
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		87,460	0
28	Accumulated Provision for Injuries and Damages (228.2)		577,000	577,000
29	Accumulated Provision for Pensions and Benefits (228.3)		137,888,376	103,108,963
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	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)		7,722,821	5,660,557
35	Total Other Noncurrent Liabilities (lines 26 through 34)		146,275,657	109,346,520
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	51,194,606
38	Accounts Payable (232)		64,637,846	68,930,607
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		3,598,930	1,360,978
41	Customer Deposits (235)		1,142,378	1,089,390
42	Taxes Accrued (236)	262-263	12,180,596	10,855,486
43	Interest Accrued (237)		6,827,000	4,253,960
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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STATEMENT OF INCOME

Quarterly

- 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.
- 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.
- 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.
- 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.
- If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

- Do not report fourth quarter data in columns (e) and (f)
- Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
- Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

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	402,135,463	364,701,808		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	239,585,126	223,802,793		
5	Maintenance Expenses (402)	320-323	33,223,158	27,414,190		
6	Depreciation Expense (403)	336-337	41,002,229	40,695,885		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	65,640	54,645		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	1,294,748	810,698		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	49,025	48,941		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		1,101,302	2,187,739		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		33,411	334,300		
13	(Less) Regulatory Credits (407.4)		549,480	514,284		
14	Taxes Other Than Income Taxes (408.1)	262-263	12,599,569	11,305,254		
15	Income Taxes - Federal (409.1)	262-263	-2,411,627	-1,331,495		
16	- Other (409.1)	262-263	-466,417	-266,006		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	8,304,094	31,916,567		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	-5,390,442	21,939,569		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,903,783	-1,925,310		
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)		100	66		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		478,263	454,062		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		337,795,600	313,048,344		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		64,339,863	51,653,464		

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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 purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.

12. If any notes appearing in the report to stockholders 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
402,135,463	364,701,808					2
						3
239,585,126	223,802,793					4
33,223,158	27,414,190					5
41,002,229	40,695,885					6
65,640	54,645					7
1,294,748	810,698					8
49,025	48,941					9
1,101,302	2,187,739					10
						11
33,411	334,300					12
549,480	514,284					13
12,599,569	11,305,254					14
-2,411,627	-1,331,495					15
-466,417	-266,006					16
8,304,094	31,916,567					17
-5,390,442	21,939,569					18
-1,903,783	-1,925,310					19
						20
						21
100	66					22
						23
478,263	454,062					24
337,795,600	313,048,344					25
64,339,863	51,653,464					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)		64,339,863	51,653,464		
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)		950,932	984,638		
34	(Less) Expenses of Nonutility Operations (417.1)		554,609	613,122		
35	Nonoperating Rental Income (418)		55,509	54,945		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		236,959	257,848		
38	Allowance for Other Funds Used During Construction (419.1)		1,543,423	1,822,917		
39	Miscellaneous Nonoperating Income (421)		4,098,851	8,986,820		
40	Gain on Disposition of Property (421.1)			8,196		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		6,331,065	11,502,242		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		12,771	24,557		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		464,813	526,442		
46	Life Insurance (426.2)					
47	Penalties (426.3)					
48	Exp. for Certain Civic, Political & Related Activities (426.4)		215,069	239,895		
49	Other Deductions (426.5)		849,539	3,837,633		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		1,542,192	4,628,527		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	6,787	5,880		
53	Income Taxes-Federal (409.2)	262-263	2,536,661	1,477,089		
54	Income Taxes-Other (409.2)	262-263	466,419	266,012		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	-584,063	2,010,918		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	302,745	929,888		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		2,123,059	2,830,011		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		2,665,814	4,043,704		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		22,774,908	17,199,173		
63	Amort. of Debt Disc. and Expense (428)		394,099	387,011		
64	Amortization of Loss on Required Debt (428.1)		362,452	337,182		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Required Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		479,398	539,699		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		689,294	1,002,253		
70	Net Interest Charges (Total of lines 62 thru 69)		23,321,563	17,460,812		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		43,684,114	38,236,356		
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)		43,684,114	38,236,356		

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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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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		138,400,473	134,730,951
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)		43,684,114	38,236,356
17	Appropriations of Retained Earnings (Acct. 436)			
18	Excess hydro licensing amortization		-74,482	(61,467)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-74,482	(61,467)
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			-35,408,269	(34,505,367)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-35,408,269	(34,505,367)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		146,601,836	138,400,473
	APPROPRIATED RETAINED EARNINGS (Account 215)			

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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)
39	Amortization reserve, federal (account 215.1)		512,681	438,199
40				
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)		512,681	438,199
	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)		512,681	438,199
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		147,114,517	138,838,672
	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)			

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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)	43,684,114	38,236,356
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	41,067,869	40,750,531
5	Amortization	1,737,872	1,246,649
6	Vehicle depreciation allocated to various operating accounts	1,737,917	1,575,392
7			
8	Deferred Income Taxes (Net)	13,090,716	13,110,370
9	Investment Tax Credit Adjustment (Net)	-1,903,783	-3,011,582
10	Net (Increase) Decrease in Receivables	-1,543,420	-958,566
11	Net (Increase) Decrease in Inventory	-1,337,538	1,269,089
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	8,115,787	-688,360
14	Net (Increase) Decrease in Other Regulatory Assets	-53,467,791	62,703,996
15	Net Increase (Decrease) in Other Regulatory Liabilities	267,029	233,803
16	(Less) Allowance for Other Funds Used During Construction	1,543,423	1,822,917
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other: (Increase) decrease in noncurrent assets and deferred debits	1,430,612	-98,848
19	Other: Increase(decrease) in noncurrent liabilities & deferred credits	36,492,949	-56,668,591
20	Other: (Increase) decrease in other current assets	-290,312	-1,207,508
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	87,538,598	94,669,814
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-150,846,464	-160,695,183
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-178,600	265,540
30	(Less) Allowance for Other Funds Used During Construction	-1,543,423	-1,822,917
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-149,481,641	-158,606,726
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)		

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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.
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Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables	-1,330,000	-3,264,000
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses	1,596,000	12,634,000
53	Other: (Increase) decrease in funds on deposit with trustee	758,649	35,876
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-148,456,992	-149,200,850
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	150,000,000	40,900,000
62	Preferred Stock		
63	Common Stock		
64	Other: Debt issuance expense	-686,328	-283,874
65			
66	Net Increase in Short-Term Debt (c)		51,194,606
67	Other: Change in checks written in excess of cash	-4,744,224	3,156,989
68	Other: Proceeds from capital infusions	44,000,000	22,400,000
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	188,569,448	117,367,721
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-40,900,000	-40,635,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)	-51,194,606	
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-35,408,269	-34,505,367
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	61,066,573	42,227,354
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	148,179	-12,303,682
87			
88	Cash and Cash Equivalents at Beginning of Period	29,355	12,333,037
89			
90	Cash and Cash Equivalents at End of period	177,534	29,355

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
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FOOTNOTE DATA			

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

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

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

Changes in miscellaneous deferred debits.

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

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

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

Change in special funds on deposit with fiscal agent.

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

Debt issuance expense.

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

Change in checks written in excess of cash.

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

Proceeds from capital infusions from parent company.

Name of Respondent Otter Tail Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report 12/31/2014	Year/Period of Report End of 2014/Q4
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NOTES TO FINANCIAL STATEMENTS

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

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

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
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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 are considered cash equivalents.

	2014	2013
Cash Equivalents	\$ 177,534	\$ 0
Reconciliation	2014	2013
Cash – Account 131 (Line 35, Page 110)	\$ 10,300	\$ 10,300
Working Fund – Account 135 (Line 37, Page 110)	19,055	19,055
Cash Equivalent – Account 136 (Above)	<u>148,179</u>	<u>0</u>
	\$ 177,534	\$ 29,355

Otter Tail Power Company

Notes to Financial Statements

For the years ended December 31, 2014 and 2013

1. Summary of Significant Accounting Policies

Organization and Operations

Otter Tail Power Company was incorporated in 1907 under the laws of the State of Minnesota. In 2001, the name was changed to “Otter Tail Corporation” to more accurately represent the broader scope of consolidated operations and the name Otter Tail Power Company (OTP) was retained for use by the electric utility.

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 an active wholesale participant in the Midcontinent Independent Transmission System Operator (MISO) markets.

OTP provides electricity to more than 130,000 customers in a service area encompassing of 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 125,646 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, 2014, OTP served 130,490 customers. Although there are relatively few large customers, sales to commercial and industrial customers are significant.

Related Party

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

<i>(in thousands)</i>	2014	2013
Accounts Receivable	\$ 45	\$ 11
Accounts Payable	3,599	1,571
Operating Revenues	114	70
Other Operation and Maintenance Expenses	9,200	8,083
Interest Expense	--	427

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.

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NOTES TO FINANCIAL STATEMENTS (Continued)			

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

Regulation and ASC 980

OTP, a regulated electric utility company, accounts for the financial effects of regulation in accordance with the requirements of Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 980, *Regulated Operations* (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.
- Certain commodity trading purchases and sales transactions are presented gross as expense and revenues for the FERC presentation; however the net margin is reported as net sales for the GAAP presentation.
- Various revenues and expenses are presented as other income and income deductions for the FERC presentation and reported as operating income and expenses for the GAAP presentation.

Plant, Retirements and Depreciation

Utility plant is stated at original cost. The cost of additions includes contracted work, direct labor and materials, allocable overheads and allowance for funds used during construction. The amount of interest capitalized on electric utility plant was \$689,000 in 2014 and \$1,002,000 in 2013. 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 costs. 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 service lives of the properties (5 to 70 years). Such provisions as a percent of the average balance of depreciable electric utility property were 2.89% in 2014 and 2.96% in 2013. Gains or losses on group asset dispositions are taken to the accumulated provision for depreciation reserve and impact current and future depreciation rates.

Jointly Owned Facilities

The balance sheets include OTP's ownership interests in the assets and liabilities of Big Stone Plant (53.9%) and Coyote Station (35.0%). The following amounts are included in the December 31, 2014 and 2013 balance sheets:

<i>(in thousands)</i>	2014	2013
Big Stone Plant:		
Electric Plant in Service	\$ 143,746	\$ 142,780
Construction Work in Progress	160,809	94,913
Accumulated Depreciation	(86,211)	(83,005)
Net Plant	\$ 218,344	\$ 154,688

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NOTES TO FINANCIAL STATEMENTS (Continued)			

Coyote Station:		
Electric Plant in Service	\$ 163,824	\$ 162,095
Construction Work in Progress	1,725	303
Accumulated Depreciation	(99,364)	(96,907)
<u>Net Plant</u>	<u>\$ 66,185</u>	<u>\$ 65,491</u>

OTP is a joint owner, with other regional utilities, in three major transmission lines and two additional major planned transmission line projects with the following ownership interests: 14.8% in the Bemidji-Grand Rapids 230 kV line, approximately 14.1% in the Fargo-Monticello 345 kV line, approximately 4.8% in the Brookings-Southeast Twin Cities Multi-Value Project (MVP) 345 kV line, 50.0% in the Big Stone South to Brookings MVP 345 kV line and 50.0% in the Big Stone South to Ellendale MVP 345 kV line. The following amounts for the jointly-owned transmission facilities are included in OTP's December 31, 2014 and 2013 balance sheets:

<i>(in thousands)</i>	2014	2013
Electric Plant in Service	\$ 68,648	\$ 26,337
Construction Work in Progress	59,163	71,205
Accumulated Depreciation	(1,758)	(837)
<u>Net Plant</u>	<u>\$ 126,053</u>	<u>\$ 96,705</u>

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

Coyote Station Lignite Supply Agreement – Variable Interest Entity

In October 2012, the Coyote Station owners, including OTP, entered into a lignite sales agreement (LSA) with Coyote Creek Mining Company, L.L.C. (CCMC), a subsidiary of The North American Coal Corporation, for the purchase of 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 to be paid by the Coyote Station owners under the LSA will reflect the cost of production, along with an agreed profit and capital charge. CCMC was formed for the purpose of mining lignite 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. Therefore, CCMC is not required to be consolidated in OTP's financial statements.

Under the LSA, all development period costs of the Coyote Creek coal mine incurred during the development period will be recovered from the Coyote Station owners over the full term of the production period, which commences with the first delivery of coal to Coyote Station, scheduled for May 2016, by being included in the cost of production. The development fee and the capital charge incurred during the development period will be recovered from the Coyote Station owners over the first 52 months of the production period by being included in the cost of production during those months. OTP's 35% share of development period costs, development fees and capital charges incurred by CCMC through December 31, 2014 is \$21.6 million. 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, 2014 could be as high as \$21.6 million.

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

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NOTES TO FINANCIAL STATEMENTS (Continued)			

generated by the asset.

Income Taxes

Otter Tail Corporation and its subsidiaries, including OTP, file a consolidated U.S. federal income tax return and various state and foreign income tax returns. In OTP's financial statements, comprehensive interperiod income tax allocation is used for substantially all book and tax temporary differences. 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 to the financial statements regarding OTP's accounting for uncertain tax positions.

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 OTP's deferred tax assets. To the extent facts and circumstances change in the future, adjustments to the valuation allowance may be required.

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.

In the case of derivative instruments, such as OTP's forward energy contracts, marked-to-market and realized gains and losses are recognized on a net basis in revenue in accordance with ASC Topic 815, *Derivatives and Hedging* (ASC 815). Gains and losses on forward energy contracts subject to regulatory treatment, if any, are deferred and recognized on a net basis in revenue in the period realized. OTP's unrealized gains and losses on forward energy contracts that do not meet the definition of capacity contracts are marked to market and reflected on a net basis in electric revenue on its statement of income. Under ASC 815, OTP's forward energy contracts that do not meet the definition of a capacity contract and are subject to unplanned netting do not qualify for the normal purchase and sales exception from mark-to-market accounting. See note 4 to the financial statements for further discussion.

Use of Estimates

OTP uses estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used for such items as depreciable lives, tax provisions, collectability of trade accounts receivable, self-insurance programs, unbilled electric revenues, accrued renewable resource, transmission and environmental cost recovery rider revenues, valuations of forward energy contracts and actuarially determined benefits costs and liabilities. As better information becomes available (or actual amounts are known), the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Cash Equivalents

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

Investments

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

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NOTES TO FINANCIAL STATEMENTS (Continued)			

<i>(in thousands)</i>	2014	2013
Cost Method:		
Economic Development Loan Pools	\$ 174	\$ 219
Equity Method:		
Partnerships	22	19
Total Investments	\$ 196	\$ 238

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 hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. The three levels defined by the hierarchy and examples of each level are as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reported date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices, such as equities listed by the New York Stock Exchange and commodity derivative contracts listed on the New York Mercantile Exchange (NYMEX).

Level 2 – Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities.

Level 3 – Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation and may include complex and subjective models and forecasts.

The following tables present, for each of the fair value hierarchy levels, OTP's assets and liabilities that are measured at fair value on a recurring basis as of December 31:

2014 (in thousands)	Level 1	Level 2	Level 3
Assets:			
Current Assets – Other:			
Forward Energy Contracts	\$ --	\$ --	\$ 257
Liabilities:			
Derivative Liabilities - Forward Gasoline Purchase Contracts	\$ --	\$ 342	\$ --
Derivative Liabilities - Forward Energy Contracts	--	--	13,888
2013 (in thousands)	Level 1	Level 2	Level 3
Assets:			
Current Assets – Other:			
Forward Energy Contracts	\$ --	\$ --	\$ 338
Forward Gasoline Purchase Contracts		62	
Liabilities:			
Derivative Liabilities - Forward Energy Contracts	\$ --	\$ 103	\$ 11,679

The valuation techniques and inputs used for the Level 2 fair value measurements in the table above are as follows:

Forward Energy Contracts – Prices used for the fair valuation of these forward purchases and sales of electricity, which have illiquid trading points, are indexed to a price at an active market.

Forward Gasoline Purchase Contracts – These contracts are priced based on NYMEX quoted prices for Reformulated Blendstock for Oxygenate Blending (RBOB) Gasoline contracts. Prices used for the fair valuation of these contracts are based on NYMEX

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daily reporting date quoted prices for RBOB contracts with the same settlement periods.

Fair values for OTP's forward energy contracts with delivery points that are not at an active trading hub included in Level 3 of the fair value hierarchy in the table above as of December 31, 2014 and December 31, 2013, are based on prices indexed to observable prices at an active trading hub. Prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models. The December 31, 2014 Level 3 forward electric basis spreads ranged from \$2.50 to \$7.97 per megawatt-hour under the active trading hub price. The weighted average price was \$34.95 per megawatt-hour.

In the table above, the fair value of the Level 3 forward energy contracts in derivative asset and derivative liability positions as of December 31, 2014 are related to power purchase contracts where OTP intends to take or has taken physical delivery of the energy under the contract. When OTP takes physical delivery of the energy purchased under these contracts the costs incurred are subject to recovery in base rates and through fuel clause adjustments. Any derivative assets or liabilities and related gains or losses recorded as a result of the fair valuation of these power purchase contracts will not be realized and are 100% offset by regulatory liabilities and assets related to fuel clause adjustment treatment of purchased power costs. Therefore, the net impact of any recorded fair valuation gains or losses related to these contracts on OTP's net income is \$0 and the net income impact of any future fair valuation adjustments of these contracts will be \$0. When energy is delivered under these contracts, they will be settled at the original contract price and any fair valuation gains or losses and related derivative assets or liabilities recorded over the life of the contracts will be reversed along with any offsetting regulatory liabilities or assets. Because of regulatory accounting treatment, any price volatility related to the fair valuation of these contracts had no impact on OTP's reported net income for the years ended December 31, 2014 and 2013.

The following table presents changes in Level 3 forward energy contract derivative asset and liability fair valuations for the twelve-month periods ended December 31, 2014 and 2013:

<i>(in thousands)</i>	2014	2013
Forward Energy Contracts - Fair Values Beginning of Period	\$ (11,341)	\$ (17,782)
Less: Amounts Reversed on Settlement of Contracts Entered into in Prior Periods	2,785	7,943
Changes in Fair Value of Contracts Entered into in Prior Periods	166	(640)
Cumulative Fair Value Adjustments of Contracts Entered into in Prior Years at End of Period	(8,390)	(10,479)
Net Decrease in Value of Open Contracts Entered into in Current Period	(5,241)	(862)
Forward Energy Contracts - Net Derivative Liability Fair Values End of Period	\$ (13,631)	\$ (11,341)

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,	
	2014	2013
Noncash Investing Activities:		
Accounts Payable Outstanding Related to Capital Additions ¹	\$ 23,801	\$ 22,205
Accounts Receivable Outstanding Related to Joint Plant Owner's Share of Capital Additions ²	\$ 4,594	\$ 3,264

¹Amounts are included in cash used for capital expenditures in subsequent periods when payables are settled.

²Amounts are deducted from cash used for capital expenditures in subsequent periods when cash is received.

<i>(in thousands)</i>	2014	2013
Cash Paid During the Year for:		
Interest (net of amount capitalized)	\$ 19,992	\$ 17,140
Income Tax Payments (Refunds)	\$ 55	\$ --

New Accounting Standards

Accounting Standards Update (ASU) 2013-11

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In July 2013, the FASB issued ASU 2013-11, *Income Taxes (Topic 740) (ASC 740), Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists*, which requires an entity with unrecognized tax benefits to present the unrecognized tax benefits as a reduction to a deferred tax asset related to a net operating loss carryforward, a similar tax loss, or a tax credit carryforward when such net operating loss carryforward, similar tax loss, or tax credit carryforward is available at the reporting date under the tax law of the applicable jurisdiction to settle any additional income taxes that would result from the disallowance of a tax position. The ASU 2013-11 amendments to ASC 740 are effective for fiscal years beginning after December 15, 2013. OTP adopted the reporting requirements in ASU 2013-11 in the first quarter of 2014 on a prospective basis and transferred \$4.3 million of unrecognized tax benefits from other long-term liabilities to long-term deferred income taxes.

ASU 2014-09

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606) (ASC 606)*. ASC 606 is a comprehensive, principles-based accounting standard which amends current revenue recognition guidance with the objective of improving revenue recognition requirements by providing a single comprehensive model to determine the measurement of revenue and the timing of revenue recognition. ASC 606 also requires expanded disclosures to enable users of financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers.

ASU 2014-09 amendments to the ASC are effective for fiscal years beginning after December 15, 2016. Application methods permitted are: (1) full retrospective, (2) retrospective using one or more practical expedients and (3) retrospective with the cumulative effect of initial application recognized at the date of initial application. Early application of the ASU amendments is not permitted. OTP is currently reviewing ASU 2014-09, identifying key impacts to its businesses, reviewing revenue streams and contracts to determine areas where the amendments in ASU 2014-09 will be applicable and evaluating transition options.

2. Rate and Regulatory Matters

Below are descriptions of OTP's major capital expenditure projects that have had, or will have, a significant impact on OTP's revenue 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 2014 or 2013.

Major Capital Expenditure Projects

The Big Stone South – Brookings Project—This is a planned 345 kiloVolt (kV) transmission line that will extend approximately 70 miles between a proposed substation near Big Stone City, South Dakota and the Brookings County Substation near Brookings, South Dakota. OTP and Xcel Energy jointly developed this project. MISO approved this project as an MVP under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff) in December 2011. MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple areas within the MISO region. The cost allocation is designed to ensure that the costs of transmission projects with regional benefits are properly assigned to those who benefit. A Notice of Intent to Construct Facilities (NICF) was filed with the SDPUC on February 29, 2012. The SDPUC approved the certification for the northern portion of the route on April 9, 2013 and granted approval of a route permit for the southern portion of the line on February 18, 2014. On August 1, 2014 OTP and Xcel Energy entered into agreements to construct the project. This line is expected to be in service in 2017.

The Big Stone South – Ellendale Project—This is a proposed 345 kV transmission line that will extend 160 to 170 miles between a proposed substation near Big Stone City, South Dakota and a proposed substation near Ellendale, North Dakota. OTP is jointly developing this project with Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. (MDU). MISO approved this project as an MVP under the MISO Tariff in December 2011. OTP and MDU jointly filed an NICF with the SDPUC in March of 2012. On August 25, 2013 the NDPSC granted Certificates of Public Convenience and Necessity to OTP and MDU for ten miles of the proposed line to be built in North Dakota. On July 10, 2014 the NDPSC approved a Certificate of Corridor Compatibility and a route permit for the North Dakota section of the proposed line. On August 22, 2014 the SDPUC issued an order approving the route permit for the South Dakota section of the proposed line. If the proposed project receives all the necessary approvals, OTP anticipates the line will be completed in 2019.

Capacity Expansion 2020 (CapX2020) Transmission Line Projects—CapX2020 is a joint initiative of eleven investor-owned,

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cooperative, and municipal utilities in Minnesota and the surrounding region to upgrade and expand the electric transmission grid to ensure continued reliable and affordable service. The CapX2020 companies identified four major transmission projects for the region: (1) the Fargo–Monticello 345 kV Project (the Fargo Project), (2) the Brookings–Southeast Twin Cities 345 kV Project (the Brookings Project), (3) the Bemidji–Grand Rapids 230 kV Project (the Bemidji Project), and (4) the Twin Cities–LaCrosse 345 kV Project. OTP is an investor in the Fargo Project, the Brookings Project and the Bemidji Project. Recovery of OTP’s CapX2020 transmission investments is through the MISO Tariff (the Brookings Project as an MVP) and, currently, Minnesota, North Dakota and South Dakota Transmission Cost Recovery (TCR) Riders.

The Fargo Project—The Monticello to St. Cloud portion of the Fargo Project was placed into service on December 21, 2011. The St. Cloud to Alexandria portion of the Fargo Project was placed into service on April 23, 2014. Construction is underway for the remaining portion of the project, which is expected to be in service in 2015.

The Brookings Project—The MISO granted unconditional approval of the Brookings Project as an MVP under the MISO Tariff in December 2011. The first phase of the 250 mile Brookings Project was energized in March 2014. Additional segments of the line were energized in April 2014. The entire project is expected to be in service in 2015.

The Bemidji Project—The Bemidji-Grand Rapids transmission line was fully energized and put into service on September 17, 2012.

Big Stone Plant Air Quality Control System (AQCS)—The South Dakota Department of Environment and Natural Resources determined that the Big Stone Plant is subject to Best-Available Retrofit Technology (BART) requirements of the Clean Air Act, based on air dispersion modeling indicating that Big Stone Plant’s emissions reasonably contribute to visibility impairment in national parks and wilderness areas in Minnesota, North Dakota, South Dakota and Michigan.

OTP is currently in the process of constructing the BART-compliant AQCS at Big Stone Plant for a current projected cost of approximately \$384 million (OTP’s 53.9% share would be \$207 million) with an expected commercial operation date of October 2015. OTP’s share of AQCS construction expenditures incurred through December 31, 2014 is \$153 million, excluding Allowance for Funds Used During Construction (AFUDC).

Big Stone II Project—On June 30, 2005 OTP and a coalition of six other electric providers entered into several agreements for the development of a second electric generating unit, named Big Stone II, at the site of the existing Big Stone Plant near Milbank, South Dakota. On September 11, 2009 OTP announced its withdrawal—both as a participating utility and as the project’s lead developer—from Big Stone II. On November 2, 2009, the remaining Big Stone II participants announced the cancellation of the Big Stone II project. OTP requested jurisdictional recovery in Minnesota, North Dakota and South Dakota of amounts it had invested in the Big Stone II project at the time of its withdrawal, discussed below under the respective jurisdictional sections of this report.

Minnesota

2010 General Rate Case— OTP’s most recent general rate increase in Minnesota of approximately \$5.0 million, or 1.6%, was granted by the MPUC in an order issued on April 25, 2011 and effective October 1, 2011. The MPUC’s written order included: (1) recovery of Big Stone II costs over five years, (2) moving recovery of wind farm assets from rider recovery to base rate recovery, (3) transfer of a portion of Minnesota Conservation Improvement Program (MNCIP) costs from rider recovery to base rate recovery, (4) transfer of the investment in two transmission lines from rider recovery to base rate recovery, and (5) changing the mechanism for providing customers with a credit for margins earned on asset-based wholesale sales of electricity from a credit to base rates to a credit to the Minnesota Fuel Clause Adjustment. Pursuant to the order, OTP’s allowed rate of return on rate base increased from 8.33% to 8.61% and its allowed rate of return on equity increased from 10.43% to 10.74%.

Renewable Energy Standards, Conservation, Renewable Resource Riders— Minnesota has a renewable energy standard which requires OTP to generate or procure sufficient renewable generation such that the following percentages of total retail electric sales to Minnesota customers come from qualifying renewable sources: 17% by 2016; 20% by 2020 and 25% by 2025. In addition, Minnesota law requires 1.5% of total Minnesota electric sales by public utilities to be supplied by solar energy by 2020. OTP is currently evaluating potential options for meeting that standard. Under certain circumstances and after consideration of costs and reliability issues, the MPUC may modify or delay implementation of the standards. OTP has acquired sufficient renewable resources to comply

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with Minnesota renewable energy standards. OTP's compliance with the Minnesota renewable energy standard will be measured through the Midwest Renewable Energy Tracking System.

Under the Next Generation Energy Act of 2007, an automatic adjustment mechanism was established to allow Minnesota electric utilities to recover investments and costs incurred to satisfy the requirements of the renewable energy standard. The MPUC is authorized to approve a rate schedule rider to enable utilities to recover the costs of qualifying renewable energy projects that supply renewable energy to Minnesota customers. Cost recovery for qualifying renewable energy projects can be authorized outside of a rate case proceeding, provided that such renewable projects have received previous MPUC approval. Renewable resource costs eligible for recovery may include return on investment, depreciation, operation and maintenance costs, taxes, renewable energy delivery costs and other related expenses.

The costs for three major wind farms previously approved by the MPUC for recovery through OTP's Minnesota Renewable Resource Adjustment (MNRRA) were moved to base rates as of October 1, 2011 under the MPUC's April 25, 2011 general rate case order with the exception of the remaining balance of the MNRRA regulatory asset. OTP continued to collect the remaining regulatory asset balance through April 30, 2013, when the balance was near zero. On April 4, 2013 the MPUC authorized that any remaining unrecovered balance be retained as a regulatory asset to be recovered in OTP's next general rate case. Effective May 1, 2013 the resource adjustment on OTP's Minnesota customers' bills no longer includes MNRRA costs.

Minnesota Conservation Improvement Programs—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 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 January 1, 2013 OTP's MNCIP surcharge decreased from 3.8% of the customer's bill to \$0.00142 per kwh, which equates to approximately 1.9% of a customer's bill. OTP recognized \$2.6 million of MNCIP financial incentives in 2012 and an additional \$0.1 million in 2013 relating to 2012 program results. On October 10, 2013 the MPUC approved OTP's 2012 financial incentive request for \$2.7 million as well as its request for an updated surcharge rate to be implemented on November 1, 2013. OTP recognized \$3.9 million in MNCIP financial incentives in 2013 related to the results of its conservation improvement programs in Minnesota in 2013. On April 1, 2014 OTP submitted its annual 2013 financial incentive filing request for \$4.0 million along with a request for an updated surcharge rate. On September 26, 2014 the MPUC approved OTP's 2013 financial incentive request for \$4.0 million, an updated surcharge rate to be effective October 1, 2014, as well as a change to the carrying charge to be equal to the short term cost of debt set in OTP's most recent general rate case. Based on preliminary results from the 2014 MNCIP program year, OTP is estimating a financial incentive for 2014 of \$2.5 million. OTP is estimating a lower incentive for 2014 in response to the MPUC lowering the MNCIP financial incentive from approximately \$0.09 per kwh saved for 2013-2015 to \$0.07 per kwh saved for 2014-2016. Also, OTP estimates it saved approximately 3 million less kwhs in 2014 compared with 2013. OTP will request approval from the MPUC in an April 1, 2015 filing.

OTP had a regulatory asset of \$8.2 million for allowable costs and financial incentives eligible for recovery through the MNCIP rider that had not been billed to Minnesota customers as of December 31, 2014. OTP's Minnesota conservation recoverable costs and incentives totaled \$7.8 million in 2014 and \$9.3 million in 2013.

Transmission Cost Recovery (TCR) Rider—In addition to the MNRRA rider, the Minnesota Public Utilities Act (the Act) provides a similar mechanism for automatic adjustment outside of a general rate proceeding to recover the costs of new transmission facilities that have been previously approved by the MPUC in a Certificate of Need (CON) proceeding, certified by the MPUC as a Minnesota priority transmission project, made to transmit the electricity generated from renewable generation sources ultimately used to provide service to the utility's retail customers, or exempt from the requirement to obtain a Minnesota CON. The MPUC may also authorize cost recovery via such TCR riders for charges incurred by a utility under a federally approved tariff that accrue from other transmission

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owners' regionally planned transmission projects that have been determined by the MISO to benefit the utility or integrated transmission system. The 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. Such TCR riders allow a return on investment at the level approved in a utility's last general rate case. Additionally, following approval of the rate schedule, the MPUC may approve annual rate adjustments filed pursuant to the rate schedule. OTP's initial request for approval of a TCR rider was granted by the MPUC on January 7, 2010, and became effective February 1, 2010.

MISO regional cost allocation allows OTP to recover some of the costs of its transmission investment from other MISO customers. On March 26, 2012 the MPUC approved an update to OTP's Minnesota TCR rider along with an all-in method for MISO regional cost allocations in which OTP's retail customers would be responsible for the entire investment OTP made in transmission facilities that qualify for regional cost allocation under the MISO Tariff, with an offsetting credit for revenues received from other MISO utilities under the MISO Tariff for projects included in the TCR. OTP's updated Minnesota TCR rider went into effect April 1, 2012.

On May 24, 2012 OTP filed a petition with the MPUC to seek a determination of eligibility for the inclusion of twelve additional transmission related projects in subsequent Minnesota TCR rider filings. On February 20, 2013 the MPUC approved three of the additional projects as eligible for recovery through the TCR rider. OTP filed its annual update to the TCR rider on February 7, 2013 to include the three new projects as well as updated costs associated with existing projects. In a written order issued on March 10, 2014, the MPUC approved OTP's 2013 TCR rider update but disallowed recovery of capitalized internal costs, costs in excess of CON estimates and a carrying charge in the TCR rider. These items were removed from OTP's Minnesota TCR rider effective March 1, 2014. OTP will be allowed to seek recovery of these costs in a future rate case. In response to the MPUC approval of OTP's annual TCR update, OTP submitted a compliance filing in April 2014 reflecting the TCR rider revenue requirements changes relating to the MPUC's ruling and requesting no rate change be implemented at the time. The MPUC approved OTP's compliance filing on June 19, 2014. OTP filed its 2014 annual update on May 1, 2014. The MNDOC recommended approval of the 2014 update on September 24, 2014. On February 18, 2015 the MPUC approved OTP's 2014 TCR rider annual update with an effective date of March 1, 2015.

OTP had a regulatory asset of \$3.4 million for amounts eligible for recovery through the Minnesota TCR rider that had not been billed to Minnesota customers as of December 31, 2014. OTP recognized revenue for amounts eligible for recovery through the Minnesota TCR rider of \$6.3 million in 2014 and \$2.9 million in 2013.

Environmental Cost Recovery (ECR) Rider—In a written order issued on January 23, 2012 the MPUC granted OTP's petition for Advance Determination of Prudence (ADP) for costs associated with the design, construction and operation of the BART-compliant AQCS at Big Stone Plant attributable to serving OTP's Minnesota customers. On May 24, 2013 legislation was enacted in Minnesota which allowed OTP to file an emission-reduction rider for recovery of the revenue requirements of the AQCS. The legislation authorizes the rider to allow a current return on investment, including Construction Work in Progress (CWIP), at the level approved in OTP's most recent general rate case, unless a different return is determined by the MPUC to be in the public interest. On December 18, 2013 the MPUC granted approval of OTP's Minnesota ECR rider for recovery of OTP's Minnesota jurisdictional share of the revenue requirements of its investment in the Big Stone Plant AQCS effective January 1, 2014. The ECR rider recoverable revenue requirements include a current return on the project's CWIP balance at the level approved in OTP's most recent general rate case. OTP filed its 2014 annual update on July 31, 2014, requesting a \$4.1 million annual increase in the rider from \$6.1 million to \$10.2 million. The MPUC approved OTP's ECR rider annual update request on November 24, 2014, effective December 1, 2014. Because the effective date was two months behind the anticipated implementation date for the updated rate and a portion of the requested increase had been collected under the initial rate, the approved updated rate is based on a revenue requirement of \$9.8 million. The rate will continue to be updated in annual filings with the MPUC until the costs are rolled into base rates at an undetermined future date.

OTP had a regulatory asset of \$0.2 million for amounts eligible for recovery through the Minnesota ECR rider that had not been billed to Minnesota customers as of December 31, 2014. OTP recognized revenue for amounts eligible for recovery through the Minnesota ECR rider of \$6.9 million in 2014.

Big Stone II Project Cost Recovery—OTP requested recovery of the Minnesota portion of its Big Stone II development costs over a five-year period as part of its general rate case filed in Minnesota on April 2, 2010. In a written order issued on April 25, 2011, the MPUC authorized recovery of the Minnesota portion of Big Stone II generation development costs from Minnesota ratepayers over a 60-month recovery period which began on October 1, 2011. The amount of Big Stone II generation costs incurred by OTP that were

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deemed recoverable from Minnesota ratepayers as part of the rates established in that proceeding was \$3.2 million. Because OTP was not allowed to earn a return on these deferred costs over the 60-month recovery period, the recoverable amount of \$3.2 million was discounted to its then present value of \$2.8 million using OTP's incremental borrowing rate, in accordance with ASC Topic 980, *Regulated Operations* (ASC 980) accounting requirements. Transmission-related project costs of \$3.2 million remained in CWIP as active project costs at the time of the order.

Approximately \$0.4 million of the total Minnesota jurisdictional share of Big Stone II transmission costs were transferred to the Big Stone South - Brookings MVP transmission line project in the first quarter of 2013. The remaining transmission costs, along with accumulated AFUDC, were transferred from CWIP to a regulatory asset account in May 2013, based on recovery granted in the April 25, 2011 order. Because OTP was not allowed to earn a return on these deferred costs over their anticipated recovery period, the recoverable amount of approximately \$3.5 million was discounted to its then present value using OTP's incremental borrowing rate. In May 2013, OTP recorded a charge of \$0.7 million related to the discount in accordance with ASC 980 accounting requirements. In June 2014, OTP recorded an additional discount of \$0.3 million to reflect changes in the end date of the anticipated recovery period from September 2020 to December 2022.

North Dakota

General Rates—OTP's most recent general rate increase in North Dakota of \$3.6 million, or approximately 3.0%, was granted by the NDPSC in an order issued on November 25, 2009 and effective December 2009.

Renewable Resource Adjustment—OTP has a North Dakota Renewable Resource Adjustment (NDRRA) which enables OTP to recover the North Dakota share of its investments in renewable energy facilities it owns in North Dakota. This rider allows OTP to recover costs associated with new renewable energy projects as they are completed. On March 21, 2012 the NDPSC approved an update to OTP's NDRRA effective April 1, 2012. The updated NDRRA recovered \$9.9 million over the period April 1, 2012 through March 31, 2013. On December 28, 2012 OTP submitted its annual update to the NDRRA with a proposed effective date of April 1, 2013. The update resulted in a rate reduction, so the NDPSC did not issue an order suspending the rate change. Consequently, pursuant to statute, OTP was allowed to implement updated rates effective April 1, 2013. On July 10, 2013, the NDPSC approved the updated rates implemented on April 1, 2013. The NDPSC approved OTP's most recent annual update to the NDRRA on March 12, 2014 with an effective date of April 1, 2014. The update approved on March 12, 2014 resulted in a 13.5% reduction in the NDRRA rate. On December 31, 2014 OTP submitted its annual update to the NDRRA with a proposed effective date of April 1, 2015.

OTP had a regulatory liability of \$1.0 million as of December 31, 2014 for amounts billed to North Dakota customers that were subject to refund through the NDRRA rider. OTP recognized revenue for amounts eligible for recovery through the NDRRA rider of \$7.5 million in 2014 and \$8.6 million in 2013.

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. On April 29, 2011 OTP filed a request for an initial North Dakota TCR rider with the NDPSC, which was approved on April 25, 2012 and effective May 1, 2012. On August 31, 2012 OTP filed its annual update to the North Dakota TCR rider rate to reflect updated cost information associated with projects then in the rider, as well as proposing to include costs associated with ten additional projects for recovery within the rider. The NDPSC approved the annual update on December 12, 2012 with an effective date of January 1, 2013. On August 30, 2013 OTP filed its annual update to its North Dakota TCR rider rate, which was approved on December 30, 2013 and became effective January 1, 2014. On August 29, 2014 OTP filed its annual update to the North Dakota TCR rider rate. Within this TCR filing, as required by the order for the North Dakota Big Stone II rider, OTP included the over-collection of North Dakota Big Stone II abandoned plant costs of \$0.1 million. The NDPSC approved the annual update on December 17, 2014 with an effective date of January 1, 2015.

OTP had a regulatory asset of \$0.9 million for amounts eligible for recovery through the North Dakota TCR rider that had not been billed to North Dakota customers as of December 31, 2014. OTP recognized revenue for amounts eligible for recovery through the North Dakota TCR rider of \$5.8 million in 2014 and \$3.2 million in 2013.

Environmental Cost Recovery Rider—On May 9, 2012 the NDPSC approved OTP's application for an ADP related to the Big Stone Plant AQCS. On February 8, 2013 OTP filed a request with the NDPSC for an ECR rider to recover OTP's North Dakota jurisdictional share of the revenue requirements associated with its investment in the Big Stone Plant AQCS. On December 18, 2013

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the NDPSC approved OTP's North Dakota ECR rider based on revenue requirements through the 2013 calendar year and thereafter, with rates effective for bills rendered on or after January 1, 2014. On March 31, 2014 OTP filed its annual update to its North Dakota ECR rider rate. The update included a request to increase the ECR rider rate from 4.319% of base rates to 7.531% of base rates. On July 10, 2014 the NDPSC approved OTP's 2014 ECR rider annual update request with an August 1, 2014 implementation date.

OTP had a regulatory asset of \$0.7 million for amounts eligible for recovery through the North Dakota ECR rider that had not been billed to North Dakota customers as of December 31, 2014. OTP recognized revenue for amounts eligible for recovery through the North Dakota ECR rider of \$5.9 million in 2014 and \$2.3 million in 2013.

Big Stone II Project—In an order issued June 25, 2010, the NDPSC authorized recovery of Big Stone II development costs from North Dakota ratepayers, pursuant to a final settlement agreement filed June 23, 2010, between the NDPSC advocacy staff, OTP and the North Dakota Large Industrial Energy Group, Interveners. The terms of the settlement agreement indicate that OTP's discontinuation of participation in the project was prudent and OTP should be authorized to recover the portion of costs it incurred related to the Big Stone II generation project. The total amount of Big Stone II generation costs incurred by OTP (which excluded \$2.6 million of project transmission-related costs) was determined to be \$10.1 million, of which \$4.1 million represents North Dakota's jurisdictional share.

OTP included in its total recovery amount a carrying charge of approximately \$0.3 million on the North Dakota share of Big Stone II generation costs for the period from September 1, 2009 through the date the recovery of costs began based on OTP's average 2009 AFUDC rate of 7.65%. Because OTP would not earn a return on these deferred costs over the 36-month recovery period, the recoverable amount of \$4.3 million was discounted to its then present value of \$3.9 million using OTP's incremental borrowing rate, in accordance with ASC 980 accounting requirements. The North Dakota portion of Big Stone II generation costs was recovered over a 36-month period which began on August 1, 2010.

The North Dakota jurisdictional share of Big Stone II costs incurred by OTP related to transmission was \$1.1 million. Approximately \$0.3 million of the total North Dakota jurisdictional share of Big Stone II transmission costs were transferred to the Big Stone South - Brookings MVP during the first quarter of 2013. On July 30, 2013 the NDPSC approved OTP's request to continue the Big Stone II cost recovery rates for an additional eight months through March 31, 2014 to recover the remaining North Dakota share of Big Stone II transmission-related costs plus accrued AFUDC totaling \$1.0 million. As of April 1, 2014 North Dakota customer's bills no longer include a charge for North Dakota share of Big Stone II costs. OTP had a regulatory liability of \$0.1 million as of December 31, 2014 for amounts billed to North Dakota customers that will be refunded through the North Dakota TCR rider.

South Dakota

2010 General Rate Case—On April 21, 2011, the SDPUC issued a written order approving an overall revenue increase for OTP of approximately \$643,000 (2.32%) and an overall rate of return on rate base of 8.50%. Final rates were effective with bills rendered on and after June 1, 2011.

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 submitted a request for an initial South Dakota TCR rider to the SDPUC on November 5, 2010. The South Dakota TCR was approved by the SDPUC and implemented on December 1, 2011. The SDPUC approved an annual update to OTP's South Dakota TCR on April 23, 2013 with an effective date of May 1, 2013. The SDPUC approved OTP's following annual update to its South Dakota TCR on February 18, 2014 with an effective date of March 1, 2014. OTP filed another annual update on October 31, 2014, which was approved by the SDPUC on February 13, 2015 with an effective date of March 1, 2015.

OTP had a regulatory liability of less than \$0.1 million as of December 31, 2014 for amounts billed to South Dakota customers that were subject to refund through the South Dakota TCR rider. OTP recognized revenue for amounts eligible for recovery through the South Dakota TCR rider of \$1.2 million in 2014 and \$0.8 million in 2013.

Environmental Cost Recovery Rider—On March 30, 2012 OTP requested approval from the SDPUC for an ECR rider to recover costs associated with the Big Stone Plant AQCS. On April 17, 2013 OTP filed a request to either suspend or withdraw this filing. The SDPUC approved withdrawing this filing on April 23, 2013. On August 29, 2014 OTP filed a new request with the SDPUC for an ECR rider to recover costs associated with new environmental measures including costs to comply with mercury and air toxics

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standards. On November 25, 2014 the SDPUC approved OTP's ECR rider request to recover the costs of the Big Stone Plant AQCS and Hoot Lake Plant Mercury and Air Toxics Standards (MATS) projects, with an effective date of December 1, 2014.

OTP had a regulatory asset of less than \$0.1 million for amounts eligible for recovery through the South Dakota ECR rider that had not been billed to South Dakota customers as of December 31, 2014. OTP recognized revenue for amounts eligible for recovery through the South Dakota ECR rider of \$0.2 million in 2014.

Big Stone II Project—OTP requested recovery of the South Dakota portion of its Big Stone II development costs over a five-year period as part of its general rate case filed in South Dakota on August 20, 2010. In the first quarter of 2011, the SDPUC approved recovery of the South Dakota portion of Big Stone II generation development costs totaling approximately \$1.0 million from South Dakota ratepayers over a ten-year period beginning in February 2011 with the implementation of interim rates. OTP is allowed to earn a return on the amount subject to recovery over the ten-year recovery period. Therefore, the South Dakota settlement amount is not discounted. OTP transferred the South Dakota portion of the remaining Big Stone II transmission costs to CWIP, with such costs subject to AFUDC and recovery in future FERC-approved MISO rates or retail rates. On July 31, 2012 the SDPUC approved the transfer of the Big Stone II transmission route permits to OTP.

A portion of the Big Stone II transmission costs were transferred out of CWIP in February 2013 to be included within the Big Stone South - Brookings MVP. On March 28, 2013 OTP filed a petition with the SDPUC requesting deferred accounting for the remaining unrecovered Big Stone II transmission costs until OTP's next South Dakota general rate case. The petition was approved by the SDPUC on April 23, 2013 and in May 2013 OTP transferred the remaining South Dakota jurisdictional portion of unrecovered Big Stone II transmission costs plus accumulated AFUDC totaling \$0.2 million from CWIP to the Big Stone II Unrecovered Project Costs – South Dakota regulatory asset accounts.

FERC

Wholesale power sales and transmission rates are subject to the jurisdiction of the FERC under the Federal Power Act of 1935, as amended. The FERC is an independent agency with jurisdiction over rates for wholesale electricity sales, transmission and sale of electric energy in interstate commerce, interconnection of facilities, and accounting policies and practices. Filed rates are effective after a one day suspension period, subject to ultimate approval by the FERC.

Effective January 1, 2010 the FERC authorized OTP's implementation of a forward looking formula transmission rate under the MISO Tariff. OTP was also authorized by the FERC to recover in its formula rate (1) 100% of prudently incurred CWIP in rate base and (2) 100% of prudently incurred costs of transmission facilities that are cancelled or abandoned for reasons beyond OTP's control (Abandoned Plant Recovery), as determined by the FERC subsequent to abandonment, specifically for three regional transmission CapX2020 projects in which OTP is a joint owner: the Fargo Project, the Bemidji Project and the Brookings Project.

Effective January 1, 2012, the FERC authorized OTP to recover 100% of prudently incurred CWIP and Abandoned Plant Recovery on two projects approved by MISO as MVPs in MISO's 2011 Transmission Expansion Plan: the Big Stone South – Brookings MVP and the Big Stone South – Ellendale MVP.

Multi-Value Transmission Projects—On December 16, 2010 the FERC approved the cost allocation for a new classification of projects in the MISO region called MVPs. MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple transmission zones within the MISO region. The cost allocation is designed to ensure that the costs of transmission projects with regional benefits are properly assigned to those who benefit. On October 20, 2011 the FERC reaffirmed the MVP cost allocation on rehearing. On June 7, 2013, in response to a challenge to the MVP cost allocation heard before the United States Court of Appeals, Seventh Circuit, the Court ruled in favor of MISO and MISO transmission owners, issuing an order affirming the FERC's approval of the MVP cost allocation. On February 24, 2014 the U.S. Supreme Court denied petitions for a writ of certiorari of the Seventh Circuit's decision upholding the FERC's MVP orders. The petitioners did not seek rehearing.

On November 12, 2013 a group of industrial customers and other stakeholders filed a complaint with the FERC seeking to reduce the return on equity component of the transmission rates that MISO transmission owners, including OTP, may collect under the MISO Tariff. The complainants are seeking to reduce the current 12.38% return on equity used in MISO's transmission rates to a proposed

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9.15%. A group of MISO transmission owners have filed responses to the complaint, defending the current return on equity and seeking dismissal of the complaint. On October 16, 2014 the FERC issued an order finding that the current MISO return on equity may be unjust and unreasonable and setting the issue for hearing, subject to the outcome of settlement discussion. Settlement discussions did not resolve the dispute and the FERC set the proceeding to a Track II Hearing for complex cases that can take several months to decide, with a FERC decision anticipated in fall 2016 at the earliest. 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 (RTO) participation (RTO Adder). On January 5, 2015 the FERC granted the request, deferring collection of the RTO Adder until the resolution of the return on equity complaint proceeding.

3. Regulatory Assets and Liabilities

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

<i>(in thousands)</i>	December 31, 2014 Total	Remaining Recovery/ Refund Period
Regulatory Assets:		
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits ¹	\$108,990	see note
Deferred Marked-to-Market Losses ¹	13,888	72 months
Conservation Improvement Program Costs and Incentives ²	8,343	18 months
Accumulated ARO Accretion/Depreciation Adjustment ¹	5,190	asset lives
Minnesota Transmission Rider Accrued Revenues ²	3,398	24 months
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up ¹	3,392	24 months
Deferred Income Taxes ¹	2,086	asset lives
North Dakota Transmission Rider Accrued Revenues ²	859	12 months
North Dakota Environmental Cost Recovery Rider Accrued Revenues ²	706	12 months
Minnesota Environmental Cost Recovery Rider Accrued Revenues ²	186	12 months
Minnesota Renewable Resource Rider Accrued Revenues ²	68	see note
South Dakota Environmental Cost Recovery Rider Accrued Revenues ²	38	12 months
Total Regulatory Assets	\$ 147,144	
Regulatory Liabilities:		
Deferred Income Taxes	1,550	asset lives
North Dakota Renewable Resource Rider Accrued Refund	1,018	15 months
Revenue for Rate Case Expenses Subject to Refund – Minnesota	784	see note
Deferred Marked-to-Market Gains	257	67 months
Big Stone II Over Recovered Project Costs – North Dakota	147	12 months
Deferred Gain on Sale of Utility Property – Minnesota Portion	106	228 months
South Dakota Transmission Rider Accrued Refund	48	12 months
South Dakota – Nonasset-Based Margin Sharing Excess	24	12 months
Total Regulatory Liabilities	\$ 3,934	
Net Regulatory Asset Position	\$ 143,210	

¹ Costs subject to recovery without a rate of return.

² 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, 2013 Total	Remaining Recovery/ Refund Period
Regulatory Assets:		
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits ¹	\$ 59,107	see note
Deferred Marked-to-Market Losses ¹	11,682	60 months
Conservation Improvement Program Costs and Incentives ²	8,905	18 months
Accumulated ARO Accretion/Depreciation Adjustment ¹	4,646	asset lives
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up ¹	3,104	24 months
North Dakota Environmental Cost Recovery Rider Accrued Revenues ²	2,331	12 months
Deferred Income Taxes ¹	1,805	asset lives
North Dakota Renewable Resource Rider Accrued Revenues ²	762	15 months
Minnesota Renewable Resource Rider Accrued Revenues ²	68	see note
South Dakota Transmission Rider Accrued Revenues ²	32	12 months
Deferred Holding Company Formation Costs ¹	27	6 months
General Rate Case Recoverable Expenses – South Dakota ¹	6	1 month
Total Regulatory Assets	\$ 92,475	
Regulatory Liabilities:		
Deferred Income Taxes	1,960	asset lives
Minnesota Transmission Rider Accrued Refund	670	12 months
Revenue for Rate Case Expenses Subject to Refund – Minnesota	289	see note
North Dakota Renewable Resource Rider Accrued Refund	261	12 months
North Dakota Transmission Rider Accrued Refund	215	12 months
Deferred Marked-to-Market Gains	123	56 months
Deferred Gain on Sale of Utility Property – Minnesota Portion	111	240 months
South Dakota – Nonasset-Based Margin Sharing Excess	38	12 months
Total Regulatory Liabilities	\$ 3,667	
Net Regulatory Asset Position	\$ 88,808	

¹Costs subject to recovery without a rate of return.

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

The regulatory 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.

All Deferred Marked-to-Market Gains and Losses recorded as of December 31, 2014 are related to forward purchases of energy scheduled for delivery through December 2020.

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

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

Minnesota Transmission Rider Accrued Revenues relate to revenues earned on qualifying transmission system facilities that have not

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been billed to Minnesota customers as of December 31, 2014.

MISO Schedule 26/26A Transmission Cost Recovery Rider True-up relates to the over/under collection of revenue based on comparison of the expected versus actual construction on eligible projects in the period. The true-up also includes 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.

The regulatory assets and liabilities related to Deferred Income Taxes result from changes in statutory tax rates accounted for in accordance with ASC Topic 740.

North Dakota Transmission Rider Accrued Revenues relate to revenues earned on qualifying transmission system facilities that have not been billed to North Dakota customers as of December 31, 2014.

North Dakota Environmental Cost Recovery Rider Accrued Revenues relate to a return granted on the North Dakota share of amounts invested in the construction of the Big Stone Plant AQCS project, net of amounts billed under the rider.

Minnesota Environmental Cost Recovery Rider Accrued Revenues relate to a return granted on the Minnesota share of amounts invested in the construction of the Big Stone Plant AQCS project, net of amounts billed under the rider.

Minnesota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying renewable resource costs incurred to serve Minnesota customers that have not been billed to Minnesota customers. On April 4, 2013 the MPUC approved OTP's request to set the MNRRRA rate to zero effective May 1, 2013 and authorized that any unrecovered balance be retained as a regulatory asset to be recovered in OTP's next general rate case.

South Dakota Environmental Cost Recovery Rider Accrued Revenues relate to a return granted on the South Dakota share of amounts invested in the construction of the Big Stone Plant AQCS project and Hoot Lake Plant MATS project, net of amounts billed under the rider.

The North Dakota Renewable Resource 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, 2014.

Revenue for Rate Case Expenses Subject to Refund – Minnesota relate to revenues collected under general rates to recover costs related to prior rate case proceedings in excess of the actual costs incurred, which are subject to refund.

Big Stone II Over Recovered Project Costs – North Dakota represent amounts collected from North Dakota customers in excess of the North Dakota share of generation and transmission plant-related costs incurred by OTP related to its participation in the abandoned Big Stone II generation project. The December 31, 2014 liability will be refunded to North Dakota customers through an adjustment to revenue requirements under the North Dakota TCR rider.

South Dakota Transmission 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, 2014.

South Dakota – Nonasset-Based Margin Sharing Excess represents 25% of OTP's South Dakota share of actual profit margins on nonasset-based wholesale sales of electricity. The excess margins accumulated annually will be subject to refund through future retail rate adjustments in South Dakota in the following year.

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 the balance sheet and included in the statement of income as an extraordinary expense or income item in the period in which the application of guidance under ASC 980 ceases.

4. Forward Contracts Classified as Derivatives

Electricity Contracts

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All of OTP's wholesale purchases and sales of energy under forward contracts that do not meet the definition of capacity contracts are considered derivatives subject to mark-to-market accounting. OTP's objective in entering into forward contracts for the purchase and sale of energy is to meet the energy requirements of its retail customers and to optimize the use of its generating and transmission facilities. OTP's intent in entering into certain of these contracts is to settle them through the physical delivery of energy when physically possible and economically feasible. Prior to December 2014, OTP also entered into certain contracts for trading purposes with the intent to profit from fluctuations in market prices through the timing of purchases and sales. Effective December 31, 2014 OTP discontinued its trading activities not directly associated with serving retail customers.

Market prices used to value OTP's forward contracts for the purchases and sales of electricity are determined by survey of counterparties or brokers used by OTP's power services' personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange and CME Globex. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models. The fair value measurements of these forward energy contracts fall into Level 3 of the fair value hierarchy set forth in ASC 820.

Electric operating revenues include wholesale electric sales and net unrealized derivative gains on forward energy contracts, the acquisition and settlement of financial transmission rights and congestion revenue rights options in the MISO and Electric Reliability Council of Texas (ERCOT) markets and daily settlements of virtual transactions in the MISO, ERCOT and California Independent Transmission System Operator markets, broken down as follows for the years ended December 31:

<i>(in thousands)</i>	2014	2013
Wholesale Sales - Company-Owned Generation	\$ 11,160	\$ 14,846
Revenue from Settled Contracts at Market Prices	131,952	133,238
Market Cost of Settled Contracts	(130,908)	(132,055)
Net Margins on Settled Contracts at Market	1,044	1,183
Marked-to-Market Gains on Settled Contracts	263	3,039
Marked-to-Market Losses on Settled Contracts	(276)	(2,722)
Net Marked-to-Market (Losses) Gains on Settled Contracts	(13)	317
Unrealized Marked-to-Market Gains on Open Contracts	--	215
Unrealized Marked-to-Market Losses on Open Contracts	(--)	(100)
Net Unrealized Marked-to-Market Gains on Open Contracts	--	115
Wholesale Electric Revenue	\$ 12,191	\$ 16,461

The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity and the location and fair value amounts of the related derivatives reported on OTP's balance sheets as of December 31, 2014 and December 31, 2013, and the change in OTP's balance sheet position from December 31, 2013 to December 31, 2014 and December 31, 2012 to December 31, 2013:

<i>(in thousands)</i>	December 31, 2014	December 31, 2013
Other Current Asset – Marked-to-Market Gain	\$ 257	\$ 338
Regulatory Asset – Current Deferred Marked-to-Market Loss	4,492	3,008
Regulatory Asset – Long-Term Deferred Marked-to-Market Loss	9,396	8,674
Total Assets	14,145	12,020
Current Liability – Marked-to-Market Loss	(13,888)	(11,782)
Regulatory Liability – Current Deferred Marked-to-Market Gain	--	(6)
Regulatory Liability – Long-Term Deferred Marked-to-Market Gain	(257)	(117)
Total Liabilities	(14,145)	(11,905)
Net Fair Value of Marked-to-Market Energy Contracts	\$ --	\$ 115

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<i>(in thousands)</i>	Year ended December 31, 2014	Year ended December 31, 2013
Cumulative Fair Value Adjustments Included in Earnings - Beginning of Period	\$ 115	\$ 49
Less: Amounts Realized on Settlement of Contracts Entered into in Prior Periods	(72)	(49)
Changes in Fair Value of Contracts Entered into in Prior Periods	(43)	--
Cumulative Fair Value Adjustments in Earnings of Contracts Entered into in Prior Years at End of Period	--	--
Changes in Fair Value of Contracts Entered into in Current Period	--	115
Cumulative Fair Value Adjustments Included in Earnings - End of Period	\$ --	\$ 115

OTP has established guidelines and limits to manage credit risk associated with wholesale power and capacity purchases and sales. Specific limits are determined by a counterparty's financial strength. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch). OTP had no exposure at December 31, 2014 to counterparties with investment grade or below investment grade credit ratings with respect to any of its forward energy contracts.

Individual counterparty exposures for certain contracts can be offset according to legally enforceable netting arrangements. However, OTP does not net offsetting payables and receivables or derivative assets and liabilities under legally enforceable netting arrangements on the face of its balance sheet. The amounts of derivative asset and derivative liability balances that were subject to legally enforceable netting arrangements as of December 31, 2014 and December 31, 2013 are indicated in the following table:

<i>(in thousands)</i>	December 31, 2014	December 31, 2013
Derivative Assets Subject to Legally Enforceable Netting Arrangements	\$ 257	\$ 400
Derivative Liabilities Subject to Legally Enforceable Netting Arrangements	(14,230)	(11,782)
Net Balance Subject to Legally Enforceable Netting Arrangements	\$ (13,973)	\$ (11,382)

The following table provides a breakdown of OTP's credit risk standing on forward energy contracts in marked-to-market loss positions as of December 31, 2014 and December 31, 2013:

<i>(in thousands)</i>	December 31, 2014	December 31, 2013
Current Liability – Marked-to-Market Loss		
Loss Contracts Covered by Deposited Funds or Letters of Credit	\$ 45	\$ --
Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade ¹	13,888	11,679
Loss Contracts with No Ratings Triggers or Deposit Requirements	297	103
Total Current Liability – Marked-to-Market Loss	\$ 14,230	\$ 11,782

¹ Certain OTP derivative energy contracts contain provisions that require an investment grade credit rating from each of the major credit rating agencies on OTP's debt. If OTP's debt ratings were to fall below investment grade, the counterparties to these forward energy contracts could request the immediate deposit of cash to cover contracts in net liability positions.

Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade	\$ 13,888	\$ 11,679
Offsetting Gains with Counterparties under Master Netting Agreements	(257)	(117)
Reporting Date Deposit Requirement if Credit Risk Feature Triggered	\$ 13,631	\$ 11,562

5. Common Shareholder's Equity

Otter Tail Corporation completed its holding company reorganization in July 2009. In conjunction with the reorganization, OTP issued 100 shares of common stock with a par value of \$5 per share, with the sole holder of those shares being Otter Tail Corporation. In 2014, Otter Tail Corporation made cash equity contributions to OTP totaling \$44,000,000. In 2013, Otter Tail Corporation made a \$22,400,000 cash equity contribution to OTP.

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6. Retained Earnings and Dividend Restriction

OTP's credit agreement contains 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, 2014 OTP was in compliance with the debt 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, 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 45.0% and 55.0%. OTP's equity to total capitalization ratio including short-term debt was 49.8% as of December 31, 2014. Total capitalization for OTP cannot currently exceed \$987 million.

7. Commitments and Contingencies

Construction and Other Purchase Commitments

At December 31, 2014 OTP had commitments under contracts in connection with construction programs extending into 2018 of approximately \$106.6 million.

Capacity and Energy Requirements and Coal and Delivery Contracts

OTP has commitments for the purchase of capacity and energy requirements under agreements extending into 2039. OTP has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. OTP's current coal purchase agreements, under which OTP is committed to the minimum purchase amounts or to make payments in lieu thereof, expire in 2015, 2016, 2017 and 2040. Fuel clause adjustment mechanisms lessen the risk of loss from market price changes because they provide for recovery of most fuel costs. See table below for schedule of commitments.

Operating Leases

OTP has obligations to make future operating lease payments primarily related to land leases and coal rail-car leases. Rent expense from operations was \$2,680,000 for 2014 and \$2,641,000 for 2013.

The amounts of OTP's commitments under capacity and energy agreements, coal and coal delivery contracts and operating leases as of December 31, 2014, are as follows:

<i>(in thousands)</i>	Construction Program Commitments	Capacity and Energy Requirements	Coal and Freight Purchase Commitments	Operating
2015	\$ 48,708	\$ 34,383	\$ 49,739	\$ 1,958
2016	40,653	22,812	22,943	1,371
2017	17,163	22,123	28,146	978
2018	100	22,729	23,135	990
2019	--	24,532	23,072	1,002
Beyond 2019	--	217,359	598,742	10,824
Total	\$ 106,624	\$ 343,938	\$ 745,777	\$ 17,123

Contingencies

On June 21, 2010 the EPA published a proposed rule that outlines two possible options to regulate disposal of coal ash generated from the combustion of coal by electric utilities under the Resource Conservation and Recovery Act (RCRA). In one option, the EPA would propose to list coal ash destined for disposal in landfills or surface impoundments as "special wastes" subject to regulation under Subtitle C of RCRA. Subtitle C regulations set forth the EPA's hazardous waste regulatory program, which regulates the generation, handling, transport and disposal of wastes. Under the other proposed regulatory option, the EPA would regulate the disposal of coal ash under Subtitle D of RCRA, the regulatory program for nonhazardous solid wastes. On December 19, 2014 the EPA announced a

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final rule following the Subtitle D nonhazardous provisions. The rule requires OTP to complete certain actions, such as installing additional groundwater monitoring wells and investigating whether existing surface impoundments meet defined location restrictions, in order to determine whether existing surface impoundments should be retired or retrofitted with liners. Therefore, the cost impact of this rule will not be known until those actions are completed. Existing landfill cells can continue to operate as designed, but future expansions will require composite liner and leachate collection systems. The EPA is also considering future regulation of coal ash under Subtitle C. Publication of the final rule will open a 90-day window within which petitions for judicial review may be filed in the D.C. Circuit. Challenges by environmental groups are possible and the outcome of such challenges cannot be predicted. Thus, uncertainty regarding the status of this rule is likely to continue for some time.

Other

OTP is a party to litigation 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, 2014 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, 2014 and December 31, 2013:

<i>(in thousands)</i>	Line Limit	In Use on December 31, 2014	Restricted due to Outstanding Letters of Credit	Available on December 31, 2014	Available on December 31, 2013
OTP Credit Agreement	\$ 170,000	\$ --	\$ 560	\$ 169,440	\$ 116,975

Under the OTP Credit Agreement (as defined below), the maximum amount of debt outstanding in 2014 was \$97,000,000 on February 13, 2014 and the average daily balance of debt outstanding during 2014 was \$12,815,000. The weighted average interest rate paid on debt outstanding under the OTP Credit Agreement during 2014 was 1.4% compared with 1.4% in 2013.

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 November 3, 2014 the OTP Credit Agreement was amended to extend its expiration date by one year from October 29, 2018 to October 29, 2019. 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. OTP is required to pay commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The OTP Credit Agreement contains a number of restrictions on the business of OTP, including restrictions on its ability to merge, sell assets, make investments, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The OTP Credit Agreement also contains affirmative covenants and events of default, and financial covenants as described below under the heading "Financial Covenants." The OTP Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. OTP's obligations under the OTP Credit Agreement are not guaranteed by any other party.

Long-Term Debt Issuances and Retirements

Debt Retirements

On March 1, 2013 OTP entered into a Credit Agreement (the Loan Agreement) with JPMorgan Chase Bank, N.A. (JPMorgan) providing for a \$40.9 million unsecured term loan (the Term Loan) to OTP originally due on June 1, 2014, which was fully drawn on March 1, 2013. The Loan Agreement was amended on October 29, 2013 to extend the due date on the Term Loan to January 15, 2015. Borrowings under the Loan Agreement bore interest at LIBOR plus 0.875%. On March 1, 2013 OTP utilized approximately \$25.1 million of Term Loan proceeds to fund the redemption price for all of the 4.65% Grant County, South Dakota Pollution Control Refunding Revenue Bonds and 4.85% Mercer County, North Dakota Pollution Control Refunding Revenue Bonds outstanding on that date, in each case for which OTP paid debt service. All such bonds had been called for redemption in full on March 1, 2013. Also on

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March 1, 2013, OTP utilized approximately \$15.7 million of Term Loan proceeds to satisfy an intercompany note to Otter Tail Corporation that had a balance and interest rate designed to equate to the balances and dividend rates of Otter Tail Corporation's cumulative preferred shares. On February 27, 2014 OTP used a portion of the proceeds from the issuance of notes under the 2013 Note Purchase Agreement (as defined below) to retire early the Term Loan.

2013 Note Purchase Agreement

On August 14, 2013 OTP entered into a Note Purchase Agreement (the 2013 Note Purchase Agreement) pursuant to which OTP has agreed to issue to the purchasers named therein, 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. OTP used a portion of the proceeds of the Notes to retire early the Term Loan as discussed above and to repay OTP's short-term debt outstanding on February 27, 2014. The remaining proceeds of the Notes were used to pay fees and expenses related to the issuance of the Notes and for other general purposes, including construction program expenditures.

The 2013 Note Purchase Agreement states that OTP may prepay all or any part of the Notes (in an amount not less than 10% of the aggregate principal amount of the Notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount, provided that if no default or event of default under the 2013 Note Purchase Agreement exists, any optional prepayment made by OTP of (i) all of the Series A Notes then outstanding on or after November 27, 2028 or (ii) all of the Series B Notes then outstanding on or after November 27, 2043, will be made at 100% of the principal prepaid but without any make-whole amount. In addition, the 2013 Note Purchase Agreement states OTP must offer to prepay all of the outstanding Notes at 100% of the principal amount together with unpaid accrued interest in the event of a change of control 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 OTP's existing 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 (an "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 \$155 million senior unsecured notes issued in four series consisting of \$33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, due 2017; \$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).

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

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also states that OTP must offer to prepay all of the outstanding notes issued thereunder at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of OTP. The note purchase agreements contain a number of restrictions on OTP, including restrictions on OTP's ability to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The note purchase agreements also include affirmative covenants and events of default, and certain financial covenants as described below under the heading "Financial Covenants."

The aggregate amounts of maturities on bonds outstanding and other long-term obligations at December 31, 2014 for each of the next five years are:

<i>(in thousands)</i>	2015	2016	2017	2018	2019
Aggregate amounts of Debt Maturities	\$ --	\$ --	\$ 33,000	\$ --	\$ --

Financial Covenants

OTP was in compliance with the financial covenants in its debt agreements as of December 31, 2014.

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

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

- Under the OTP Credit Agreement and the Loan Agreement (when in effect), 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, 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, each as provided in the 2013 Note Purchase Agreement.

9. Pension Plan and Other Postretirement Benefits

For valuation of OTP's pension and other postretirement benefit projected benefit obligations as of December 31, 2014, Otter Tail Corporation adopted updated and modified mortality tables and an updated and modified mortality improvement scale that reflect longer life expectancies for plan participants. The adoption of the updated and modified mortality tables and mortality improvement scale in 2014 increased OTP's pension and other postretirement benefit obligations from projected benefit obligations that would have been rendered using the mortality tables Otter Tail Corporation had been using since 2005. Although the adoption of the updated and modified tables and improvement scale will have the effect of increasing the estimated and recognized cost of future benefit payments in the near term, the ultimate cost recognized will be determined by the actual level and duration of future benefit payments.

Pension Plan

The noncontributory funded pension plan covers substantially all OTP nonunion employees hired prior to January 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

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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>	2014	2013
Service Cost–Benefit Earned During the Period	\$ 4,554	\$ 5,448
Interest Cost on Projected Benefit Obligation	12,796	11,808
Expected Return on Assets	(16,341)	(14,143)
Amortization of Prior-Service Cost from Regulatory Asset	257	333
Amortization of Net Actuarial Loss from Regulatory Asset	3,400	6,600
Net Periodic Pension Cost	\$ 4,666	\$ 10,046

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

	2014	2013
Discount Rate	5.30%	4.50%
Long-Term Rate of Return on Plan Assets	7.75%	7.75%
Rate of Increase in Future Compensation Level	3.13%	3.13%

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

<i>(in thousands)</i>	2014	2013
Regulatory Assets:		
Unrecognized Prior Service Cost	\$ 518	\$ 776
Unrecognized Actuarial Loss	97,722	56,051
Total Regulatory Assets	\$ 98,240	\$ 56,827
Noncurrent Liability	\$ 65,451	\$ 39,371

Funded status as of December 31:

<i>(in thousands)</i>	2014	2013
Accumulated Benefit Obligation	\$(267,330)	\$(218,532)
Projected Benefit Obligation	\$(304,170)	\$(247,434)
Fair Value of Plan Assets	238,719	208,063
Funded Status	\$ (65,451)	\$ (39,371)

The following tables provide a reconciliation of the changes in the OTP portion of the fair value of plan assets and the plan's benefit obligations over the two-year period ended December 31, 2014:

<i>(in thousands)</i>	2014	2013
Reconciliation of OTP's Portion of the Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	\$ 208,063	\$ 186,051
Actual Return on Plan Assets	21,449	22,348
Discretionary Company Contributions	20,000	10,000
Benefit Payments	(10,793)	(10,336)
Fair Value of Plan Assets at December 31	\$ 238,719	\$ 208,063
Estimated Asset Return	9.6%	11.8%
Reconciliation of OTP's Portion of the Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	\$ 247,434	\$ 268,467
Service Cost	4,554	5,448
Interest Cost	12,796	11,808
Benefit Payments	(10,793)	(10,336)
Actuarial Loss (Gain)	50,179	(27,953)
Projected Benefit Obligation at December 31	\$ 304,170	\$ 247,434

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

	2014	2013
Discount Rate	4.35%	5.30%
Rate of Increase in Future Compensation Level	3.13%	3.13%

The assumed rate of return on pension fund assets used for the determination of 2015 net periodic pension cost is 7.75%. The assumed long-term rate of return on plan assets is based primarily on asset category studies using historical market return and volatility data with forward looking estimates based on existing financial market conditions and forecasts of capital markets. Modest excess return expectations versus some market indices are incorporated into the return projections based on the actively managed structure of the investment programs and their records of achieving such returns historically. The rate of return on plan asset assumptions are reviewed annually. The assumptions are largely based on the asset category rate-of-return assumptions developed annually with the pension plan investment advisors, as well as input from actuaries who work with the pension plan.

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 is based 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:	2014	2013
Net Periodic Pension Cost	January 1, 2014	January 1, 2013
End of Year Benefit Obligations	January 1, 2014 projected to December 31, 2014	January 1, 2013 projected to December 31, 2013
Market Value of Assets	December 31, 2014	December 31, 2013

The estimated amounts of unrecognized net actuarial losses and prior service cost to be amortized from regulatory assets into the net periodic pension cost in 2015 are:

<i>(in thousands)</i>	2015
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	\$ 189
Amortization of Unrecognized Actuarial Loss	6,529
Total Estimated Amortization	\$ 6,718

Cash flows—OTP had no minimum funding requirement as of December 31, 2014, but OTP made a discretionary plan contribution of \$10,000,000 in January 2015.

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

<i>(in thousands)</i>	2015	2016	2017	2018	2019	Years 2020-2024
	\$11,740	\$12,338	\$12,985	\$13,802	\$14,518	\$84,469

The following objectives guide the investment strategy of OTP's pension plan (the Plan):

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

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

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

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

Asset Class / PBO Funded Status	Permitted Range			
	< 100% PBO	100% PBO	105% PBO	>=110% PBO
Equity	30% - 65%	25% - 60%	20% - 55%	15% - 50%
Investment Grade Fixed Income	35% - 75%	40% - 80%	45% - 85%	50% - 90%
Below Investment Grade Fixed Income*	0% - 15%	0% - 15%	0% - 15%	0% - 15%
Other**	0% - 20%	0% - 20%	0% - 20%	0% - 20%

* 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, 2014 and 2013, by asset category are as follows:

Asset Allocation	2014	2013
Large Capitalization Equity Securities	21.0%	21.0%
International Equity Securities	18.9%	21.7%
Small and Mid-Capitalization Equity Securities	7.9%	8.5%
SEI Dynamic Asset Allocation Fund	5.5%	5.2%
Equity Securities	53.3%	56.4%
Fixed-Income Securities and Cash	42.7%	39.3%
Other - SEI Special Situation Collective Investment Trust	4.0%	4.3%
	100.0%	100.0%

Fair Value Measurements of Pension Fund Assets

ASC 715, *Compensation – Retirement Benefits*, requires disclosures about pension plan assets identified by the three levels of the fair value hierarchy established by ASC 820-10-35. The three levels defined by the hierarchy and examples of each level are as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reported date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices, such as equities listed by the New York Stock Exchange and commodity derivative contracts listed on the New York Mercantile Exchange.

Level 2 – Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported

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date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities.

Level 3 – Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation and may include complex and subjective models and forecasts.

The following table presents, for each of these hierarchy levels, OTP's pension fund assets measured at fair value as of December 31, 2014 and 2013:

2014 (in thousands)	Level 1	Level 2	Level 3
Large Capitalization Equity Securities Mutual Fund	\$ 50,171		
International Equity Securities Mutual Funds	45,176		
Small and Mid-Capitalization Equity Securities Mutual Fund	18,729		
SEI Dynamic Asset Allocation Mutual Fund	13,218		
Fixed Income Securities Mutual Funds	101,855		
Cash Management – Money Market Fund	5		
SEI Special Situation Collective Investment Trust Fund		\$ 9,565	
Total Assets	\$ 229,154	\$ 9,565	\$ --
2013 (in thousands)			
Large Capitalization Equity Securities Mutual Fund	\$ 43,715		
International Equity Securities Mutual Funds	45,205		
Small and Mid-Capitalization Equity Securities Mutual Fund	17,679		
SEI Dynamic Asset Allocation Mutual Fund	10,869		
Fixed Income Securities Mutual Funds	81,663		
Cash Management – Money Market Fund	--		
SEI Special Situation Collective Investment Trust Fund		\$ 8,932	
Total Assets	\$ 199,131	\$ 8,932	\$ --

The investments held by the SEI Special Situation Collective Investment Trust on December 31, 2014 and 2013 consisted of investments primarily in hedge funds that pursue alternative strategies, private equity funds and hybrid funds, as well as investments directly in other securities and financial instruments, with the objective of achieving high returns balanced against an appropriate level of volatility and market exposure over a full market cycle. The net asset value of the SEI Special Situations Collective Investment Trust is determined by using the fair value of the portfolio as of the close of business at the end of the year. Shares in the SEI Special Situation Collective Investment Trust can be redeemed at net asset value with prior notification. The fair value of the fund is calculated independently by the fund's administrator and is reviewed by Otter Tail Corporation.

Executive Survivor and Supplemental Retirement Plan (ESSRP)

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

Components of net periodic pension benefit cost:

<i>(in thousands)</i>	2014	2013
Service Cost–Benefit Earned During the Period	\$ 41	\$ 40
Interest Cost on Projected Benefit Obligation	819	763
Amortization of Prior Service Cost:		
From Regulatory Asset	22	22
From Other Comprehensive Income ¹	20	20
Amortization of Net Actuarial Loss:		

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From Regulatory Asset	142	208
From Other Comprehensive Income ¹	132	193
<u>Net Periodic Pension Cost</u>	<u>\$ 1,176</u>	<u>\$ 1,246</u>

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

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

	2014	2013
Discount Rate	5.30%	4.50%
Rate of Increase in Future Compensation Level	3.25%	3.25%

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

<i>(in thousands)</i>	2014	2013
Regulatory Assets:		
Unrecognized Prior Service Cost	\$ 91	\$ 113
Unrecognized Actuarial Loss	3,238	1,971
<u>Total Regulatory Assets</u>	<u>\$ 3,329</u>	<u>\$ 2,084</u>
Projected Benefit Obligation Liability – Net Amount Recognized	\$(17,360)	\$(16,093)
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	\$ 84	\$ 105
Unrecognized Actuarial Loss	3,005	1,829
<u>Total Accumulated Other Comprehensive Loss</u>	<u>\$ 3,089</u>	<u>\$ 1,934</u>

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, 2014 and a statement of the funded status as of December 31 of both years:

<i>(in thousands)</i>	2014	2013
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	1,113	1,137
Benefit Payments	(1,113)	(1,137)
<u>Fair Value of Plan Assets at December 31</u>	<u>\$ --</u>	<u>\$ --</u>
Reconciliation of OTP's Portion of the Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	\$ 16,093	\$ 17,600
Service Cost	41	39
Interest Cost	819	763
Benefit Payments	(1,113)	(1,137)
Liability Transfer from OTP to Otter Tail Corporation	(1,196)	--
Actuarial Loss (Gain)	2,716	(1,172)
<u>Projected Benefit Obligation at December 31</u>	<u>\$ 17,360</u>	<u>\$ 16,093</u>

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

	2014	2013
Discount Rate	4.35%	5.30%
Rate of Increase in Future Compensation Level	3.25%	3.25%

The estimated amounts of unrecognized net actuarial losses and prior service cost to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic pension cost for the ESSRP in 2015 are:

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<i>(in thousands)</i>	2015
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	\$ 16
Amortization of Unrecognized Actuarial Loss	334
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	15
Amortization of Unrecognized Actuarial Loss	310
<u>Total Estimated Amortization</u>	<u>\$ 675</u>

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>						Years
	2015	2016	2017	2018	2019	2020-2024
	\$1,170	\$1,200	\$1,177	\$1,223	\$1,315	\$6,144

Other Postretirement Benefits

OTP provides a portion of health insurance and life insurance benefits for retired OTP employees. Substantially all of OTP's electric utility employees may become eligible for health insurance benefits if they reach age 55 and have 10 years of service. There are no plan assets.

Components of net periodic postretirement benefit cost:

<i>(in thousands)</i>	2014	2013
Service Cost—Benefit Earned During the Period	\$ 1,030	\$ 1,384
Interest Cost on Projected Benefit Obligation	2,147	1,997
Amortization of Prior Service Cost from Regulatory Asset	205	205
Amortization of Net Actuarial Loss from Regulatory Asset	—	24
<u>Net Periodic Postretirement Benefit Cost</u>	<u>\$ 3,382</u>	<u>\$ 3,610</u>
<u>Effect of Medicare Part D Subsidy</u>	<u>\$ (925)</u>	<u>\$ (1,759)</u>

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

	2014	2013
Discount Rate	5.10%	4.25%

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

<i>(in thousands)</i>	2014	2013
Regulatory Asset:		
Unrecognized Prior Service Cost	\$ 335	\$ 540
Unrecognized Net Actuarial Loss (Gain)	7,086	(344)
<u>Net Regulatory Asset</u>	<u>\$ 7,421</u>	<u>\$ 196</u>
<u>Projected Benefit Obligation Liability – Net Amount Recognized</u>	<u>\$ (52,337)</u>	<u>\$ (44,046)</u>

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, 2014:

<i>(in thousands)</i>	2014	2013
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	2,316	2,004

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Benefit Payments (Net of Medicare Part D Subsidy)	(5,005)	(4,611)
Participant Premium Payments	2,689	2,607
Fair Value of Plan Assets at December 31	\$ --	\$ --
Reconciliation of OTP's Portion of the Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	\$ 44,046	\$ 57,352
Service Cost (Net of Medicare Part D Subsidy)	1,030	1,384
Interest Cost (Net of Medicare Part D Subsidy)	2,147	1,997
Benefit Payments (Net of Medicare Part D Subsidy)	(5,005)	(4,611)
Participant Premium Payments	2,689	2,607
Actuarial Loss (Gain)	7,430	(14,683)
Projected Benefit Obligation at December 31	\$ 52,337	\$ 44,046

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

	2014	2013
Discount Rate	4.20%	5.10%

Assumed healthcare cost-trend rates as of December 31:

	2014	2013
Healthcare Cost-Trend Rate Assumed for Next Year Pre-65	6.32%	6.47%
Healthcare Cost-Trend Rate Assumed for Next Year Post-65	6.63%	6.82%
Rate at Which the Cost-Trend Rate is Assumed to Decline	5.00%	5.00%
Year the Rate Reaches the Ultimate Trend Rate	2025	2025

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 2014 would have the following effects:

<i>(in thousands)</i>	1 Point Increase	1 Point Decrease
Effect on the Postretirement Benefit Obligation	\$ 7,263	\$ (5,941)
Effect on Total of Service and Interest Cost	\$ 503	\$ (404)
Effect on Expense	\$ 503	\$ (591)

Measurement Dates:	2014	2013
Net Periodic Postretirement Benefit Cost	January 1, 2014	January 1, 2013
End of Year Benefit Obligations	January 1, 2014 projected to December 31, 2014	January 1, 2013 projected to December 31, 2013

The estimated amounts of unrecognized net actuarial losses and prior service cost to be amortized from regulatory assets into the net periodic postretirement benefit cost in 2015 are:

<i>(in thousands)</i>	2015
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	\$ 205
Amortization of Unrecognized Actuarial Loss	191
Total Estimated Amortization	\$ 396

Cash flows—OTP expects to contribute \$2.6 million net of expected employee contributions for the payment of retiree medical benefits and Medicare Part D subsidy receipts in 2015. OTP expects to receive a Medicare Part D subsidy from the Federal government of approximately \$455,000 in 2015. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

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Otter Tail Power Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2014	2014/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

<i>(in thousands)</i>	2015	2016	2017	2018	2019	Years 2020-2024
	\$2,632	\$2,756	\$2,918	\$3,079	\$3,239	\$17,240

401K Plan

OTP has a 401K plan for the benefit of all its employees. Contributions made to this plan by OTP totaled \$1,782,000 for 2014 and \$1,632,000 for 2013.

Employee Stock Ownership Plan

OTP has a stock ownership plan for the benefit of all its employees. Contributions made by OTP were \$696,000 for 2014 and \$705,000 for 2013.

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:

Short-Term Debt—The carrying amount approximates fair value because the debt obligations are short-term and the balance outstanding as of December 31, 2013 related to the OTP Credit Agreement was subject to a variable interest rate of LIBOR plus 1.25%, which approximates market rates.

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. OTP's long-term debt subject to variable interest rates approximates fair value. 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, 2014		December 31, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Short-Term Investments	\$ 178	\$ 178	\$ 29	\$ 29
Short-Term Debt			(51,195)	(51,195)
Long-Term Debt including Current Maturities	(445,000)	(540,084)	(335,900)	(363,505)

11. Property, Plant and Equipment

<i>(in thousands)</i>	December 31, 2014	December 31, 2013	Service Life Range <i>(years)</i>	
			Low	High
Electric Plant				
Production	\$ 690,024	\$ 679,067	34	62
Transmission	323,496	270,606	40	55
Distribution	438,489	421,803	15	55
General	93,103	89,408	5	70
Electric Plant in Service	1,545,112	1,460,884		
Construction Work in Progress	240,170	184,780		
Other Property - Land	429	251		
Total Plant	1,785,712	1,645,915		
Less Accumulated Depreciation and Amortization	659,194	626,273		
Net Plant	\$ 1,126,518	\$ 1,019,642		

12. Income Taxes

The total income tax expense differs from the amount computed by applying the federal income tax rate (35% in 2014 and 2013) to net income before total income tax expense for the following reasons:

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Otter Tail Power Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2014	2014/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

<i>(in thousands)</i>	2014	2013
Tax Computed at Federal Statutory Rate	\$ 19,150	\$ 16,630
Increases (Decreases) in Tax from:		
State Income Taxes Net of Federal Income Tax Benefit	1,421	1,721
Federal Production Tax Credit	(7,517)	(6,612)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(849)	(863)
Investment Tax Credit Amortization	(597)	(597)
Dividend Received/Paid Deduction	(622)	(632)
Allowance for Funds Used During Construction - Equity	(505)	(638)
Tax Depreciation - Treasury Grant for Wind Farms	(152)	(304)
Differences Reversing in Excess of Federal Rates	(106)	(100)
Permanent and Other Differences	806	673
Total Income Tax Expense	\$ 11,029	\$ 9,278
Overall Effective Federal and State Income Tax Rate	20.2%	19.5%
Income Tax Expense Includes the Following:		
Current Federal Income Taxes	\$ 125	\$ 146
Deferred Federal Income Taxes	16,375	15,022
Deferred State Income Taxes	3,492	2,182
Federal Production Tax Credit	(7,517)	(6,612)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(849)	(863)
Investment Tax Credit Amortization	(597)	(597)
Total	\$ 11,029	\$ 9,278

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

<i>(in thousands)</i>	2014	2013
Deferred Tax Assets		
North Dakota Wind Tax Credits	41,783	42,241
Benefit Liabilities	25,728	25,268
Federal Production Tax Credits	18,763	17,594
Differences Related to Property	8,676	8,767
Net Operating Loss Carryforward	4,539	6,132
Investment Tax Credits	1,549	1,960
Vacation Accrual	1,667	1,417
Other	4,747	5,048
Total Deferred Tax Assets	\$ 107,452	\$ 108,427
Deferred Tax Liabilities		
Differences Related to Property	\$(270,101)	\$(263,658)
Excess Tax over Book Pension	(12,928)	(6,906)
North Dakota Wind Tax Credits	(11,543)	(11,543)
Other	(7,787)	(3,580)
Regulatory Asset	(2,087)	(5,618)
Impact of State Net Operating Losses on Federal Taxes	(1,595)	(2,152)
Renewable Resource Rider Accrued Revenue	139	(329)
Total Deferred Tax Liabilities	\$(305,902)	\$(293,786)
Deferred Income Taxes	\$(198,450)	\$(185,359)

Federal PTCs are earned as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes. OTP's kwh generation from its wind turbines eligible for PTCs increased 13.8% in 2014 compared with 2013. 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 net operating losses and tax credits available as of December 31, 2014:

<i>(in thousands)</i>	Amount	Year of Expiration			
		2015	2016	2017	2023-34
Federal Tax Credits	\$ 18,506	\$ --	\$ --	\$ --	\$ 18,506
State Net Operating Losses	4,471	--	--	--	4,471
State Tax Credits	38,033	2,339	2,339	389	32,966

The carryforward period on a portion of the North Dakota wind tax credits from the Langdon wind project is five years. OTP has adjusted its Deferred Tax Assets and Deferred Tax Credits by \$5.1 million for potential unused North Dakota wind tax credits related to the Langdon wind project.

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

<i>(in thousands)</i>	2014	2013
Balance on January 1	\$ 4,239	\$ 4,436
Increases Related to Tax Positions for Prior Years	120	98
Decreases Related to Tax Positions for Prior Years	(4,142)	(295)
Increases Related to Tax Positions for Current Year	5	--
Balance on December 31	\$ 222	\$ 4,239

The balance of unrecognized tax benefits as of December 31, 2014 would reduce OTP's effective tax rate if recognized. The total amount of unrecognized tax benefits as of December 31, 2014 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, 2014.

Otter Tail Corporation and its subsidiaries, including OTP, file a consolidated U.S. federal income tax return and various state and foreign income tax returns. As of December 31, 2014, with limited exceptions, Otter Tail Corporation is no longer subject to examinations by taxing authorities for tax years prior to 2011. On September 13, 2013 the IRS and U.S. Treasury issued final regulations on the deductibility and capitalization of expenditures related to tangible property, generally effective for tax years beginning on or after January 1, 2014. Taxpayers were allowed to elect early adoption of the regulations for the 2012 or 2013 tax year. Deferred tax liabilities at December 31, 2014 are not materially affected by the regulations. The final regulations do not impact the effect of Revenue Procedure 2013-24 issued on April 30, 2013, which provided guidance for repairs related to generation property. Among other things, the Revenue Procedure listed units of property and material components of units of property for purposes of analyzing repair versus capitalization issues. Otter Tail Corporation will adopt Revenue Procedure 2013-24 and the final tangible property regulations for income tax filings for tax year 2014.

13. Asset Retirement Obligations (AROs)

OTP's AROs are related to its coal-fired generation plants and 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 2014.

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, 2014 and 2013 are presented in the following table:

<i>(in thousands)</i>	2014	2013
<u>Asset Retirement Obligations</u>		
Beginning Balance	\$ 5,661	\$ 5,207
New Obligations Recognized	--	--

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NOTES TO FINANCIAL STATEMENTS (Continued)			

Adjustments Due to Revisions in Cash Flow Estimates	1,582	--
Accrued Accretion Settlements	478	454
Ending Balance	\$ 7,721	\$ 5,661
<u>Asset Retirement Costs Capitalized</u>		
Beginning Balance	\$ 1,477	\$ 1,477
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates Settlements	1,582	--
Ending Balance	\$ 3,059	\$ 1,477
<u>Accumulated Depreciation - Asset Retirement Costs Capitalized</u>		
Beginning Balance	\$ 462	\$ 407
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	--
Depreciation Expense Settlements	65	55
Ending Balance	\$ 527	\$ 462
<u>Settlements</u>		
Original Capitalized Asset Retirement Cost - Retired	\$ --	\$ --
Accumulated Depreciation	--	--
Asset Retirement Obligation Settlement Cost	\$ --	\$ --
Gain on Settlement – Deferred Under Regulatory Accounting	\$ --	\$ --

14. Quantitative and Qualitative disclosures About Market Risk

All of OTP's long-term debt outstanding on December 31, 2014 has fixed interest rates. OTP manages its interest rate risk through the issuance of fixed-rate debt with varying maturities, through economic refunding of debt through optional refundings, limiting the amount of variable interest rate debt, and the utilization of short-term borrowings to allow flexibility in the timing and placement of long-term debt.

OTP has not used interest rate swaps to manage net exposure to interest rate changes related to its portfolio of borrowings. OTP maintains a ratio of fixed-rate debt to total debt within a certain range. It is OTP's policy to enter into interest rate transactions and other financial instruments only to the extent considered necessary to meet its stated objectives. OTP does not enter into interest rate transactions for speculative or trading purposes.

OTP has in place an energy risk management policy with a goal to manage, through the use of defined risk management practices, price risk and credit risk associated with wholesale power sales. OTP has established guidelines and limits to manage credit risk associated with wholesale power and capacity sales. Specific limits are determined by a counterparty's financial strength. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch). OTP had no exposure at December 31, 2014 to counterparties with investment grade or below investment grade credit ratings with respect to any of its forward energy contracts.

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**SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION, AMORTIZATION AND DEPLETION**

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	1,482,208,340	1,482,208,340
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	61,227,046	61,227,046
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	1,543,435,386	1,543,435,386
9	Leased to Others		
10	Held for Future Use	29,656	29,656
11	Construction Work in Progress	240,169,972	240,169,972
12	Acquisition Adjustments	1,647,128	1,647,128
13	Total Utility Plant (8 thru 12)	1,785,282,142	1,785,282,142
14	Accum Prov for Depr, Amort, & Depl	659,193,694	659,193,694
15	Net Utility Plant (13 less 14)	1,126,088,448	1,126,088,448
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	653,900,153	653,900,153
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	3,691,353	3,691,353
22	Total In Service (18 thru 21)	657,591,506	657,591,506
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	1,602,188	1,602,188
33	Total Accum Prov (equals 14) (22,26,30,31,32)	659,193,694	659,193,694

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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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					31
					32
					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) 12/31/2014	Year/Period of Report 2014/Q4
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, 2013	1,459,207,447
January 31, 2014	1,461,300,884
February 28, 2014	1,462,348,411
March 31, 2014	1,472,008,180
April 30, 2014	1,501,661,265
May 31, 2014	1,502,901,659
June 30, 2014	1,505,387,966
July 31, 2014	1,507,930,823
August 31, 2014	1,516,990,770
September 30, 2014	1,520,271,024
October 31, 2014	1,523,409,891
November 30, 2014	1,531,419,942
December 31, 2014	1,543,435,386
13-month average for rate-making	1,500,636,434

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, 2013	184,779,895	113,919,962	70,859,933
January 31, 2014	195,570,712	121,107,836	74,462,876
February 28, 2014	204,564,669	127,713,961	76,850,708
March 31, 2014	204,979,679	134,868,087	70,111,592
April 30, 2014	184,873,225	141,529,258	43,343,967
May 31, 2014	195,432,050	149,917,351	45,514,699
June 30, 2014	207,090,919	160,861,723	46,229,196
July 31, 2014	216,223,730	168,022,883	48,200,847
August 31, 2014	220,345,344	170,207,263	50,138,081
September 30, 2014	229,954,155	176,364,240	53,589,915
October 31, 2014	240,314,419	184,141,540	56,172,879
November 30, 2014	243,873,525	184,401,499	59,472,026
December 31, 2014	240,169,972	180,625,670	59,544,302
13-month average for rate-making			58,037,771

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

- Report below the original cost of electric plant in service according to the prescribed accounts.
- In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
- Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
- For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
- Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
- Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of 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	6,088,642	882,554
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	7,390,616	882,554
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,710,632	
9	(311) Structures and Improvements	61,995,887	335,041
10	(312) Boiler Plant Equipment	203,418,209	8,025,484
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	63,167,999	1,220,997
13	(315) Accessory Electric Equipment	23,976,144	160,385
14	(316) Misc. Power Plant Equipment	5,420,909	104,523
15	(317) Asset Retirement Costs for Steam Production	294,509	2,539,681
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	359,984,289	12,386,111
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	307,623	
28	(331) Structures and Improvements	351,711	
29	(332) Reservoirs, Dams, and Waterways	3,709,281	555,797
30	(333) Water Wheels, Turbines, and Generators	1,057,183	323,709
31	(334) Accessory Electric Equipment	592,400	
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)	6,460,822	879,506
36	D. Other Production Plant		
37	(340) Land and Land Rights	126,762	
38	(341) Structures and Improvements	12,812,005	134,205
39	(342) Fuel Holders, Products, and Accessories	1,748,265	
40	(343) Prime Movers	31,687,154	359,027
41	(344) Generators	240,974,741	1,079,476
42	(345) Accessory Electric Equipment	20,708,614	-116,278
43	(346) Misc. Power Plant Equipment	492,264	30,405
44	(347) Asset Retirement Costs for Other Production	1,182,022	-957,370
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	309,731,827	529,465
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	676,176,938	13,795,082

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

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

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

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)	Line No.
				1
				2
			1,301,974	3
			6,971,196	4
			8,273,170	5
				6
				7
			1,710,632	8
338,186		-774,763	61,217,979	9
917,334		4,805	210,531,164	10
				11
385,275		774,763	64,778,484	12
80,906			24,055,623	13
55,064		-4,805	5,465,563	14
			2,834,190	15
1,776,765			370,593,635	16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
8,000			299,623	27
			351,711	28
1,015			4,264,063	29
7,028			1,373,864	30
			592,400	31
			442,624	32
				33
				34
16,043			7,324,285	35
				36
			126,762	37
			12,946,210	38
			1,748,265	39
236,488			31,809,693	40
809,186			241,245,031	41
		-68,273	20,524,063	42
		68,273	590,942	43
			224,652	44
1,045,674			309,215,618	45
2,838,482			687,133,538	46

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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	3,326,676	4,340,461
49	(352) Structures and Improvements		
50	(353) Station Equipment	78,145,172	2,873,013
51	(354) Towers and Fixtures	12,357,116	32,545,046
52	(355) Poles and Fixtures	94,749,175	5,140,462
53	(356) Overhead Conductors and Devices	81,883,560	9,762,122
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)	270,539,160	54,661,104
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	1,086,019	14,518
61	(361) Structures and Improvements		
62	(362) Station Equipment	71,102,531	4,021,274
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	66,399,847	1,617,647
65	(365) Overhead Conductors and Devices	47,102,105	1,284,302
66	(366) Underground Conduit		
67	(367) Underground Conductors and Devices	65,847,400	3,636,141
68	(368) Line Transformers	80,132,410	5,775,912
69	(369) Services	48,633,697	2,024,036
70	(370) Meters	32,358,175	1,194,045
71	(371) Installations on Customer Premises	4,276,194	245,127
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	4,843,333	228,380
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	421,781,711	20,041,382
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	29,961,663	632,255
88	(391) Office Furniture and Equipment	7,969,224	1,489,911
89	(392) Transportation Equipment	30,424,839	2,705,092
90	(393) Stores Equipment		
91	(394) Tools, Shop and Garage Equipment	4,186,552	299,194
92	(395) Laboratory Equipment		
93	(396) Power Operated Equipment	573,118	44,350
94	(397) Communication Equipment	8,681,730	532,714
95	(398) Miscellaneous Equipment		
96	SUBTOTAL (Enter Total of lines 86 thru 95)	83,319,022	5,703,516
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)	83,319,022	5,703,516
100	TOTAL (Accounts 101 and 106)	1,459,207,447	95,083,638
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)	1,459,207,447	95,083,638

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
			7,667,137	48
				49
1,458,601		-13,095	79,546,489	50
		-2,685	44,899,477	51
174,603		-18,516	99,696,518	52
97,749		-5,786	91,542,147	53
				54
			77,461	55
				56
				57
1,730,953		-40,082	323,429,229	58
				59
5,672			1,094,865	60
				61
801,649		12,509	74,334,665	62
				63
125,969		21,201	67,912,726	64
190,655		5,786	48,201,538	65
				66
311,061			69,172,480	67
544,925		2,900	85,366,297	68
47,355			50,610,378	69
1,108,897			32,443,323	70
172,377			4,348,944	71
				72
89,048			4,982,665	73
				74
3,397,608		42,396	438,467,881	75
				76
				77
				78
				79
				80
				81
				82
				83
				84
				85
			1,521,896	86
203,961			30,389,957	87
662,544			8,796,591	88
1,400,769			31,729,162	89
				90
75,920			4,409,826	91
				92
12,406			605,062	93
533,056		-2,314	8,679,074	94
				95
2,888,656		-2,314	86,131,568	96
				97
				98
2,888,656		-2,314	86,131,568	99
10,855,699			1,543,435,386	100
				101
				102
				103
10,855,699			1,543,435,386	104

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2014	Year/Period of Report 2014/Q4
FOOTNOTE DATA			

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

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

Intangible Electric Plant in Service	
December 31, 2013	7,390,616
January 31, 2014	7,386,086
February 28, 2014	7,386,086
March 31, 2014	7,388,586
April 30, 2014	7,388,586
May 31, 2014	7,388,586
June 30, 2014	7,388,586
July 31, 2014	7,447,329
August 31, 2014	7,395,718
September 30, 2014	8,079,224
October 31, 2014	8,079,224
November 30, 2014	8,079,224
December 31, 2014	8,273,170
13-month average for rate-making	7,620,848

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

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

Production Plant in Service	
December 31, 2013	676,176,938
January 31, 2014	676,190,810
February 28, 2014	676,163,822
March 31, 2014	675,514,794
April 30, 2014	675,730,753
May 31, 2014	675,720,296
June 30, 2014	675,720,296
July 31, 2014	675,725,787
August 31, 2014	680,927,924
September 30, 2014	680,920,396
October 31, 2014	680,935,415
November 30, 2014	685,148,990
December 31, 2014	687,133,538
13-month average for rate-making	678,616,135

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

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

Electric Transmission Plant in Service	
December 31, 2013	270,539,160
January 31, 2014	270,887,683
February 28, 2014	270,565,160
March 31, 2014	280,037,660
April 30, 2014	309,103,442

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) 12/31/2014	2014/Q4
FOOTNOTE DATA			

May 31, 2014	309,860,820
June 30, 2014	311,400,382
July 31, 2014	313,159,608
August 31, 2014	315,305,518
September 30, 2014	315,107,948
October 31, 2014	317,264,298
November 30, 2014	318,216,148
December 31, 2014	323,429,229
13-month average for rate-making	301,913,620

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

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

Distribution Plant in Service	
December 31, 2013	421,781,711
January 31, 2014	422,944,135
February 28, 2014	424,143,274
March 31, 2014	425,004,878
April 30, 2014	425,682,735
May 31, 2014	426,172,646
June 30, 2014	427,231,195
July 31, 2014	427,698,529
August 31, 2014	429,067,061
September 30, 2014	430,563,763
October 31, 2014	431,727,208
November 30, 2014	434,395,183
December 31, 2014	438,467,881
13-month average for rate-making	428,067,708

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

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

General Plant in Service	
December 31, 2013	83,319,022
January 31, 2014	83,892,170
February 28, 2014	84,090,070
March 31, 2014	84,062,262
April 30, 2014	83,755,750
May 31, 2014	83,759,310
June 30, 2014	83,647,507
July 31, 2014	83,899,570
August 31, 2014	84,294,550
September 30, 2014	85,599,694
October 31, 2014	85,403,745
November 30, 2014	85,580,397
December 31, 2014	86,131,568
13-month average for rate-making	84,418,124

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Various			29,656
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Various			
23				
24				
25				
26				
27				
28				
29				
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32				
33				
34				
35				
36				
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44				
45				
46				
47	Total			29,656

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) 12/31/2014	2014/Q4
FOOTNOTE DATA			

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

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

	Transmission	Distribution	Total
December 31, 2013	9,037	20,619	29,656
January 31, 2014	9,037	20,619	29,656
February 28, 2014	9,037	20,619	29,656
March 31, 2014	9,037	20,619	29,656
April 30, 2014	9,037	20,619	29,656
May 31, 2014	9,037	20,619	29,656
June 30, 2014	9,037	20,619	29,656
July 31, 2014	9,037	20,619	29,656
August 31, 2014	9,037	20,619	29,656
September 30, 2014	9,037	20,619	29,656
October 31, 2014	9,037	20,619	29,656
November 30, 2014	9,037	20,619	29,656
December 31, 2014	9,037	20,619	29,656
13-month average for rate-making			29,656

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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	Brookings SD - SE Twin Cities - Transmission Line	2,258,025
2	Ashtabula ND - Wind Farm	103,439
3	Big Stone SD - AQCS environmental Project	157,934,627
4	Big Stone SD - Brookings SD - Transmission Line	6,622,888
5	Big Stone SD - Ellendale ND - Transmission Line	6,232,618
6	Oakes ND - Area Transmission improvements	3,961,950
7	Fargo ND - St. Cloud MN - Transmission Line	38,164,583
8	Brookings SD - MN Border -Transmission Line	3,131,549
9	MN Border to Lyon County - Transmission Line	882,137
10	Lyon County - Hazel Creek - Transmission Line	1,374,845
11	Fargo ND - St. Cloud MN - Transmission Line - underlying improvements	458,177
12	Beulah ND - Coyote Station - mercury removal system	719,742
13	Summit SD - Replace transformer	972,179
14	Parshall ND - Area Transmission improvements	199,461
15	System Wide - Transmission Line analysis and GIS info collection	2,383,605
16	Big Stone SD - Transmission Line	136,022
17	Big Stone SD - Construct Transmission Line	162,901
18	Oakes ND - Transmission substation	247,647
19	Fergus Falls MN - Hoot Lake Plant - Environmental upgrade	681,330
20	Clearbrook MN to Solway MN - Transmission Line	233,286
21	Beulah ND - Coyote Station - Miscellaneous	174,298
22	Beulah ND - Coyote Station - Gas Recirculation Fan Variable Speed Drive	309,590
23	Big Stone SD - Big Stone Plant - Coal Dust Collection	115,941
24	Big Stone SD - Big Stone Plant - Replace Primary Superheat	1,852,616
25	Rugby ND - Install underground services	107,301
26	Audubon MN - Sheyenne ND - Construct Transmission Line	327,149
27	System Wide - purchase and install Transmission switches	139,865
28	Fergus Falls MN to Wahpeton ND - Transmission Line upgrades	262,928
29	Hankinson SD to Wahpeton ND - Transmission Line upgrades	179,498
30	Forman ND to Hankinson SD - Transmission Line upgrades	367,811
31	Rugby ND - Transmission interconnection for wind farm	189,679
32	Big Stone SD - Big Stone Plant - Dumper Dust Collection	796,788
33	System Wide - Upgrade 41.6 kV lines	228,664
34	System Wide - Future Generation	389,719
35	Beulah ND - Coyote Station - Boiler Feed Pump failure	339,242
36	Perham MN - Land aquisition for new substation	106,229
37	NUNDA ND - RUTLAND ND - Rebuild Transmission Line	109,222
38	New Effingtion SD - Reroute two miles of line	216,518
39	Battle Lake MN - Construct Substation	192,714
40	Kensal ND - Substation improvements	125,172
41	Rothsay MN - Provide service to new school	108,979
42	Hayti ND - Rebuild Substation	120,787
43	TOTAL	240,169,972

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) 12/31/2014	Year/Period of Report End of <u>2014/Q4</u>
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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	Enderlin ND - Install high side protection	137,441
2	Holloway MN - Rebuild substation	158,241
3	Perham MN - Extend service to new Tuffy's addition	309,823
4	Perham MN - New substation	120,355
5	Bemidji MN - distribution improvements	113,564
6	Perham MN - Construct overhead line for new substation	145,246
7	Miscellaneous projects under \$100,000	5,563,581
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
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37		
38		
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42		
43	TOTAL	240,169,972

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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	622,322,815	622,322,815		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	41,002,229	41,002,229		
4	(403.1) Depreciation Expense for Asset Retirement Costs	65,640	65,640		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,737,917	1,737,917		
7	Other Clearing Accounts	-86,521	-86,521		
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	42,719,265	42,719,265		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	10,842,927	10,842,927		
13	Cost of Removal	1,516,746	1,516,746		
14	Salvage (Credit)	2,007,271	2,007,271		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	10,352,402	10,352,402		
16	Other Debit or Cr. Items (Describe, details in footnote):	-789,525	-789,525		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	653,900,153	653,900,153		

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

20	Steam Production	241,455,839	241,455,839		
21	Nuclear Production				
22	Hydraulic Production-Conventional	3,194,359	3,194,359		
23	Hydraulic Production-Pumped Storage				
24	Other Production	81,672,868	81,672,868		
25	Transmission	103,308,022	103,308,022		
26	Distribution	188,160,340	188,160,340		
27	Regional Transmission and Market Operation				
28	General	36,108,725	36,108,725		
29	TOTAL (Enter Total of lines 20 thru 28)	653,900,153	653,900,153		

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) 12/31/2014	2014/Q4
FOOTNOTE DATA			

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

Inventory costs cleared to construction or utility operating expense.

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

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

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

Per its FERC-approved tariff, the Company uses a 13-month average of accumulated depreciation 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, 2013	307,359,915	99,700,396	180,775,747	34,486,758	622,322,815
January 31, 2014	309,239,786	99,895,830	181,379,433	34,770,540	625,285,590
February 28, 2014	311,018,538	99,577,009	181,981,127	35,095,991	627,672,665
March 31, 2014	312,184,715	99,953,140	182,537,472	35,425,273	630,100,599
April 30, 2014	313,684,367	100,276,538	183,318,435	35,389,781	632,669,121
May 31, 2014	315,511,124	100,696,242	184,052,636	35,656,004	635,916,006
June 30, 2014	317,393,199	101,029,326	184,728,977	35,878,680	639,030,183
July 31, 2014	319,335,561	101,469,164	184,881,759	36,128,591	641,815,075
August 31, 2014	320,343,512	101,913,773	185,539,416	36,473,131	644,269,832
September 30, 2014	321,927,036	101,778,375	186,214,964	36,500,666	646,421,042
October 31, 2014	323,775,500	102,253,391	186,841,146	36,559,208	649,429,246
November 30, 2014	324,714,153	102,691,062	187,657,467	36,724,859	651,787,541
December 31, 2014	326,323,066	103,308,022	188,160,340	36,108,725	653,900,153
13-month average for rate-making	317,139,267	101,118,636	184,466,840	35,784,477	638,509,221

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

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) 12/31/2014	Year/Period of Report End of <u>2014/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)	9,036,445	9,624,428	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)	5,793,264	5,779,545	Production
8	Transmission Plant (Estimated)	4,227,947	4,354,830	Various
9	Distribution Plant (Estimated)	7,355,549	7,995,012	Various
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	296,809	293,737	Fleet Service
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	17,673,569	18,423,124	
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)	26,710,014	28,047,552	

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) 12/31/2014	2014/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, 2013	5,793,263
January 31, 2014	5,727,837
February 28, 2014	5,659,947
March 31, 2014	5,677,636
April 30, 2014	5,755,877
May 31, 2014	5,671,541
June 30, 2014	5,707,035
July 31, 2014	5,727,711
August 31, 2014	5,759,145
September 30, 2014	5,771,228
October 31, 2014	5,836,626
November 30, 2014	5,780,671
December 31, 2014	5,779,545
13-month average for rate-making	5,742,159

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, 2013	4,227,947
January 31, 2014	4,308,374
February 28, 2014	4,366,430
March 31, 2014	4,504,857
April 30, 2014	4,508,834
May 31, 2014	4,495,812
June 30, 2014	4,452,188
July 31, 2014	4,339,618
August 31, 2014	4,321,615
September 30, 2014	4,376,703
October 31, 2014	4,312,524
November 30, 2014	4,393,864
December 31, 2014	4,354,830
13-month average for rate-making	4,381,815

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
December 31, 2013	7,355,549

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) 12/31/2014	Year/Period of Report 2014/Q4
FOOTNOTE DATA			

January 31, 2014	7,602,574
February 28, 2014	8,101,814
March 31, 2014	8,312,108
April 30, 2014	8,628,446
May 31, 2014	8,369,443
June 30, 2014	8,242,249
July 31, 2014	8,013,577
August 31, 2014	7,670,373
September 30, 2014	7,736,886
October 31, 2014	7,832,964
November 30, 2014	7,937,550
December 31, 2014	7,995,012
13-month average for rate-making	7,984,503

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, 2013	296,809	
January 31, 2014	290,273	
February 28, 2014	298,394	
March 31, 2014	292,461	
April 30, 2014	310,201	
May 31, 2014	328,211	
June 30, 2014	331,684	
July 31, 2014	330,516	
August 31, 2014	327,903	
September 30, 2014	313,727	
October 31, 2014	329,405	
November 30, 2014	314,648	
December 31, 2014	293,737	
13-month average for rate-making	312,151	

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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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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		2015	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	35,847.00		14,054.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)			1,256.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	14,116.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	21,731.00		15,310.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
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	92		
45	Gains	202.96	92		
46	Losses				

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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.

2016		2017		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		443,413.00		1
								2
								3
1,256.00				14,054.00		16,566.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						14,116.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
15,310.00		14,054.00		379,458.00		445,863.00		29
								30
								31
								32
								33
								34
								35
								36
202.96		202.97		9,945.16		10,757.01		36
				405.93		405.93		37
								38
				202.96		405.92		39
202.96		202.97		10,148.13		10,757.02		40
								41
								42
								43
				202.96	8	405.92	100	44
				202.96	8	405.92	100	45
								46

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	12/31/2014	2014/Q4
FOOTNOTE DATA			

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.

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(Next page is 228b)

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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		2015	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)			876.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year			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				

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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/transfers 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.

2016		2017		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
								2
								3
	876.00					1,752.00		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
	876.00					1,752.00		29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2014	Year/Period of Report 2014/Q4
FOOTNOTE DATA			

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.

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(Next page is 230b)

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) 12/31/2014	Year/Period of Report End of 2014/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	Big Stone II canceled project -ND (ND PSC order issued 06/23/2010)	6,727		See Note	-6,727	
23	- Generation					
24						
25	Big Stone II canceled project -ND (ND PSC order issued 07/20/2013)	368,704		See Note	-368,704	
27	- Transmission					
28						
29	Big Stone II canceled project -MN (MN PUC order issued 04/25/2011)	1,618,394		See Note	-557,933	1,060,461
31	- Generation					
32						
33	Big Stone II canceled project -MN (MN PUC order issued 04/25/2011)	2,906,419		419	-167,566	2,738,853
35	- Transmission					
36						
37	Big Stone II canceled project -SD (SD PUC order issued 02/11/2010)	710,685		407	-100,332	610,353
38						
39	- Generation					
40						
41	Big Stone II canceled project -SD (SD PUC order issued 04/30/2013)	232,957				232,957
42						
43	- Transmission					
44						
45						
46						
47						
48						
49	TOTAL	5,843,886			-1,201,262	4,642,624

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) 12/31/2014	Year/Period of Report 2014/Q4
FOOTNOTE DATA			

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

See footnote 2 of the Notes to Financial Statements, "Rate and Regulatory Matters," for detailed information about the Big Stone II project.

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

Accounts 407, 419, 440, 442, 444, and 445 were used.

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

This is North Dakota amortization, with interest.

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

Accounts 407, 419, 440, 442, 444, and 445 were used.

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

This is the North Dakota transmission cost amortized without interest.

Schedule Page: 230 Line No.: 29 Column: d

Accounts 407 and 419 were used.

Schedule Page: 230 Line No.: 29 Column: e

This is Minnesota amortization, with interest.

Schedule Page: 230 Line No.: 33 Column: e

This is the Minnesota transmission balance with interest accrued.

Schedule Page: 230 Line No.: 37 Column: e

This is South Dakota amortization.

Schedule Page: 230 Line No.: 41 Column: b

This is the South Dakota transmission balance that will be deferred until the next rate case.

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	Transmission Studies				
2	Turtle Lake	5,102	456	4,896	456
3	Gentilly Load Interconnection	(74)	456		456
4	Spiritwood	(1,135)	456		456
5	Clearbrook Interconnection	(213)	456		456
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	Generation Studies				
22	Courtney Wind	25,007	456	23,896	456
23	Borders Wind	12,038	456	10,631	456
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent Otter Tail Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2014	Year/Period of Report End of 2014/Q4
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OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter /Year Account Charged (d)	Written off During the Period Amount (e)	
1	Deferred Income Tax Adjustments					
2	Due to ASC 740 on:					
3	Property/Non Property Related Items	1,805,421	624,069	282	342,984	2,086,506
4						
5	Asset Retirement Obligation Capitalized					
6	Hoot Lake Plant	1,641,039	148,752			1,789,791
7	Big Stone Plant	393,021	45,998	407.4	108	438,911
8	Coyote Station	1,797,100	172,843			1,969,943
9	Wind Generation - Langdon	351,688	63,722			415,410
10	Wind Generation - Ashtabula	243,343	55,807			299,150
11	Wind Generation - Luverne	219,514	56,889			276,403
12						
13	Derivatives-Marked to Market Losses	11,681,707	24,178,979	244	21,972,266	13,888,420
14						
15	MISO Schedules 26 & 26A Accrual	1,752,759	3,370,150	See Note	1,730,705	3,392,204
16						
17	MN Renewable Resource Rider	68,361				68,361
18	ND Renewable Resource Rider	761,836	484,205	See Note	1,246,041	
19						
20	ESSRP	2,084,083	1,408,836	228.3	164,207	3,328,712
21						
22	Pension	56,826,426	45,155,067	228.3	3,741,495	98,239,998
23						
24	Rate Case Expense Deferral	6,069		407	6,069	
25						
26	Holding Co. Formation	27,342		407	27,342	
27						
28	MN Transmission Revenue Rider	1,351,652	3,397,758	See Note	1,351,652	3,397,758
29	ND Transmission Revenue Rider		930,708	See Note	71,472	859,236
30	SD Transmission Revenue Rider	31,700	136,484	See Note	168,184	
31						
32	MN Environmental Cost Recovery Rider		679,879	See Note	494,185	185,694
33	ND Environmental Cost Recovery Rider	2,330,811	180,296	See Note	1,805,784	705,323
34	SD Environmental Cost Recovery Rider		37,895			37,895
35						
36	Post Retirement Medical Benefits	196,373	7,430,087	228.3	205,421	7,421,039
37						
38	Conservation Improvement Program - MN	8,794,287	3,339,543	186	3,902,645	8,231,185
39	Energy Efficiency Program - SD	110,116	149,194	186	147,548	111,762
40	See footnote 3 in Notes to Financial Statements					
41	for amortization periods.					
42						
43						
44	TOTAL :	92,474,648	92,047,161		37,378,108	147,143,701

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) 12/31/2014	Year/Period of Report 2014/Q4
FOOTNOTE DATA			

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

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

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

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

Schedule Page: 232 Line No.: 28 Column: d

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

Schedule Page: 232 Line No.: 29 Column: d

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

Schedule Page: 232 Line No.: 30 Column: d

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

Schedule Page: 232 Line No.: 32 Column: d

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

Schedule Page: 232 Line No.: 33 Column: d

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

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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MISCELLANEOUS DEFERRED DEBITS (Account 186)

- Report below the particulars (details) called for concerning miscellaneous deferred debits.
- For any deferred debit being amortized, show period of amortization in column (a)
- 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		5,188,931	182.3	5,188,931	
3						
4	Energy Efficiency Program - SD		351,483	182.3	351,483	
5						
6	Purchase Card Accrual	165,165	2,448,504	186	2,469,086	144,583
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
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26						
27						
28						
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31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	165,165				144,583

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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	226,284	226,282
4	Medical Insurance Reserve		
5	Injuries and Damages Reserve		
6	See Note Below	108,200,464	107,225,793
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	108,426,748	107,452,075
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)	108,426,748	107,452,075

Notes

	Balance at Beginning of Year	Balance at End of Year
Post Retirement Benefits	19,717,928	20,213,258
Executive Supplemental Pension	4,622,906	4,647,369
Reserve for Bad Debts	336,739	316,338
Accrued Vacation Pay	1,417,106	1,667,394
Capitalized Int. on Construction	4,925,937	5,238,008
Post Employment Benefits	99,095	39,731
Incentive Plans	0	88,559
Nonqualified Retirement Savings	253,659	276,642
Reserve for Loan Pools	11,445	8,608
Capitalized A & G	3,558,063	3,190,560
Customer Rebates Capitalized	87,426	97,183
Asbestos Removal Costs Capitalized	218	0
Stock Incentives	73,803	51,150
CIAC Capitalized	169,725	147,098
BSII Discount	80,604	342,945
Unicap Adjustment	29,524	31,622
Medicare Part D	415,542	425,633
Research Credit Carryforward	108,141	247,069
Charitable Contributions	1,066,134	0
Severance Settlement	40,468	102,540
Flow-Through Items	217,468	167,383
State NOL Carryforward	6,132,148	4,530,389
Wind Energy Income Tax Credits-ND	42,240,743	41,783,354
ASC 740 Unamortized ITC	1,959,731	1,549,248
ASC 740 Recognition of Regulatory Assets (Liab.)	3,042,153	3,300,889
Wind Production Tax Credit Deferral (Asset)	17,593,758	18,762,822
	-----	-----
	108,200,464	107,225,793

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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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2014	Year/Period of Report End of 2014/Q4
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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
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100	500					5
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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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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	252,261,391
2	Additional parent investment	44,000,000
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40	TOTAL	296,261,391

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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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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	888,835
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 5.95%, Series A	33,000,000	424,856
11			
12	2014 Series Term Loan - Retired early on 02/27/14	40,900,000	31,657
13			
14	Senior Unsecured Notes 4.68%, Series A	60,000,000	195,814
15	Issued 03/01/13, MN Public Utilities Commission authorization,		
16	Docket No. E017/S-13-378 dated 06/21/13		
17			
18	Senior Unsecured Notes 5.47%, Series B	90,000,000	294,168
19	Issued 03/01/13, MN Public Utilities Commission authorization,		
20	Docket No. E017/S-13-378 dated 06/21/13		
21			
22			
23			
24			
25			
26			
27			
28	Account 222 - Reacquired Bonds - None		
29	Account 223 - Advances from associated companies - None		
30	Account 224 Other Long Term Debt - None		
31			
32			
33	TOTAL	485,900,000	3,429,061

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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 &10/1/2007	8/20/2037	8/20/2007	8/20/2037	50,000,000	3,235,000	4
						5
08/20/2007	08/20/2027	8/20/2007	8/20/2027	42,000,000	2,675,400	6
10/01/2007						7
10/01/2007	08/20/2022	10/01/2007	08/20/2022	30,000,000	1,845,000	8
						9
10/01/2007	08/20/2017	10/01/2007	08/20/2017	33,000,000	1,963,500	10
						11
03/01/2013	06/01/2014	3/1/2013	1/15/2015		67,083	12
						13
02/27/2014	02/27/2029	02/27/2014	02/27/2029	60,000,000	2,363,400	14
						15
						16
						17
02/27/2014	02/27/2044	02/27/2014	02/27/2044	90,000,000	4,143,525	18
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				445,000,000	22,774,908	33

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) 12/31/2014	2014/Q4
FOOTNOTE DATA			

Schedule Page: 256 Line No.: 32 Column: a

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

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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)	43,684,114
2		
3		
4	Taxable Income Not Reported on Books	
5	Interest Capitalized on Construction	1,321,425
6	Net Gain from Property Retirements	752,981
7	Miscellaneous Taxable Items	9,000
8	Conservation Improvement Programs	4,382,774
9	Deductions Recorded on Books Not Deducted for Return	
10	Add Back Federal Income Taxes (Includes Deferreds & ITC Adj.)	11,028,980
11	Provision for Reserves	7,349,436
12	Miscellaneous Unallowed Deductions	60,772,839
13		
14	Income Recorded on Books Not Included in Return	
15	Tax Exempt Interest	5,271
16	Equity in earnings of Subsidiaries	
17	Wind Rider Revenue	7,483,701
18	Miscellaneous Income Not Taxable	
19	Deductions on Return Not Charged Against Book Income	
20	Excess Tax Depreciation Over Book Depreciation	19,782,187
21	Removal Costs	2,905,739
22	Charges to Reserves	6,436,040
23	Leveraged ESOP Deduction	1,775,982
24	Sec 481(a) Cap to Repair Basis Adjustments	6,889,636
25	Miscellaneous Other Deductions	61,729,905
26		
27	Federal Tax Net Income	22,293,088
28	Show Computation of Tax:	
29	Federal Tax	7,802,581
30	Tax (Credits) and Adjustments	-7,802,581
31	Prior Period Adjustments	125,035
32	Total Federal Income Tax	125,035
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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) 12/31/2014	Year/Period of Report 2014/Q4
FOOTNOTE DATA			

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

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

Otter Tail Power Company is a member of an affiliated group which will file a consolidated Federal Income Tax Return for the year 2014. The other members of the affiliated group and their respective federal income tax provisions are as follows:

1	Otter Tail Corporation-Corporate	(3,191,585)
2	Varistar Corporation	(81,470)
3	DMI Industries, Inc.	(131,509)
4	BTD Manufacturing, Inc.	4,821,549
5	Northern Pipe Products, Inc.	3,386,142
6	Vinyltech Corporation	2,452,956
7	Otter Tail Energy Services Company	0
8	T. O. Plastics, Inc.	1,583,264
9	Shrco, Inc. (formerly ShoreMaster, Inc.)	(26,200)
10	Galva Foam Marine Industries, Inc.	43,105
11	Otter Tail Assurance Limited	(11,495)
12	Aevenia, Inc.	1,815,777
13	Foley Company	1,891,705
14	SLI, Inc. (formerly Shoreline Industries, Inc.)	0
15	ASI, Inc. (formerly Aviva Sports, Inc.)	(89,116)
16	Miller Welding & Iron Works, Inc.	(1,337,749)
	Total	11,125,376

The consolidated federal income tax liability is allocated on a separate return basis pursuant to the current tax sharing agreements between Otter Tail Corporation and the subsidiaries.

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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) 12/31/2014	Year/Period of Report End of <u>2014/Q4</u>
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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			7,918,614	7,918,615	
3	Unemployment	442		35,827	35,641	
4	FICA			4,515,402	4,515,402	
5						
6	MINNESOTA					
7	Property	7,012,001		8,194,270	7,031,270	
8	Income			1,393,482	1,393,482	
9	Unemployment	1,998		31,171	32,299	
10						
11	NORTH DAKOTA					
12	Property	2,049,999		2,149,011	2,024,011	
13	Income			414,643	414,643	
14	Unemployment	280		19,092	18,674	
15	Coal Conversion	173,230		728,997	763,116	
16						
17	SOUTH DAKOTA					
18	Property	1,599,999		1,583,602	1,508,602	
19	Unemployment	93		5,266	5,294	
20						
21	OTHER STATES					
22	Income					
23	Railcar	17,444		33,123	36,343	
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41	TOTAL	10,855,486		27,022,500	25,697,392	

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more than one year, show the required information separately for each tax year, identifying the year in column (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
		-2,411,627			10,330,241	2
628					35,827	3
					4,515,402	4
						5
						6
8,175,002		8,194,270				7
		-333,911			1,727,393	8
870					31,171	9
						10
						11
2,174,999		2,092,700			56,311	12
		-132,506			547,149	13
698					19,092	14
139,111		728,997				15
						16
						17
1,674,999		1,583,602				18
65					5,266	19
						20
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14,224					33,123	23
						24
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12,180,596		9,721,525			17,300,975	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) 12/31/2014	Year/Period of Report 2014/Q4
FOOTNOTE DATA			

Schedule Page: 262 Line No.: 2 Column: 1

Account 409.2: 2,536,661; Other: 7,793,580

Schedule Page: 262 Line No.: 3 Column: 1

Account 184

Schedule Page: 262 Line No.: 4 Column: 1

Account 184

Schedule Page: 262 Line No.: 8 Column: 1

Account 409.2: 333,911; Other: 1,393,482

Schedule Page: 262 Line No.: 9 Column: 1

Account 184

Schedule Page: 262 Line No.: 12 Column: 1

Account 921: 49,524; Account 408.2: 6,787

Schedule Page: 262 Line No.: 13 Column: 1

Account 409.2: 132,508; Other: 414,641

Schedule Page: 262 Line No.: 14 Column: 1

Account 184

Schedule Page: 262 Line No.: 19 Column: 1

Account 184

Schedule Page: 262 Line No.: 23 Column: 1

Account 151

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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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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%	26,459,824			411.4	1,306,827	
3	4%						
4	7%						
5	10%	1,827,998			411.4	596,956	
6							
7							
8	TOTAL	28,287,822				1,903,783	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
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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
25,152,997	25 Years		2
			3
			4
1,231,042	33.3 Years		5
			6
			7
26,384,039			8
			9
			10
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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) 12/31/2014	Year/Period of Report End of <u>2014/Q4</u>
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OTHER DEFERRED CREDITS (Account 253)

- Report below the particulars (details) called for concerning other deferred credits.
- For any deferred credit being amortized, show the period of amortization.
- 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	717,914	456	129,757	386,503	974,660
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
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33						
34						
35						
36						
37						
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42						
43						
44						
45						
46						
47	TOTAL	717,914		129,757	386,503	974,660

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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) 12/31/2014	Year/Period of Report End of 2014/Q4
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ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating 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	277,957,963	25,963,803	17,561,742
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	277,957,963	25,963,803	17,561,742
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	277,957,963	25,963,803	17,561,742
10	Classification of TOTAL			
11	Federal Income Tax	238,153,878	21,689,190	14,448,799
12	State Income Tax	39,804,084	4,274,613	3,112,943
13	Local Income Tax			

NOTES

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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
61,032	164,771	See Note	-1,464,825			287,721,110	2
							3
							4
61,032	164,771		-1,464,825			287,721,110	5
							6
							7
							8
61,032	164,771		-1,464,825			287,721,110	9
							10
51,101	138,088		-1,228,842			246,536,124	11
9,931	26,683		-235,983			41,184,985	12
							13

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) 12/31/2014	Year/Period of Report 2014/Q4
FOOTNOTE DATA			

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

182.3 adjustment due to ASC 740.

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

Amortization of Loss on Recquired Debt (pre holdco)	(878,141)
Big Stone II Deferred Costs	(2,161,491)
Retirements Method Change	202,771
South Dakota Flow Thru-Overheads	(10,354)
Prepaid Expenses	(102,376)
ADR Repair Allowance	(2,356,636)
Sec 162 & 174 R&D Deduction	(2,936,661)
Highway Powerline Relocation	(33,274)
AFUDC on Debt	(3,028,923)
Capitalized Overheads	(263,763)
Repairs Deduction - Basis Adjustments	(19,339,380)
Sec 481(a) Cap to Repair Basis Adjustments (PV)	4,373,048
Excess Tax Over Book Depreciation	(246,402,718)
North Dakota Investment Tax Credit - Federal Impacts	(11,542,928)
ASC 740 (SFAS 109) ADIT Credits - Property	(3,240,284)
Total	(287,721,110)

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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) 12/31/2014	Year/Period of Report End of 2014/Q4
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ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

- Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
- 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	13,067,038	19,396,172	13,830,097
5				
6	Accum. Deferred Income Tax			
7	Nonutility & Other	2,761,227		
8				
9	TOTAL Electric (Total of lines 3 thru 8)	15,828,265	19,396,172	13,830,097
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)	15,828,265	19,396,172	13,830,097
20	Classification of TOTAL			
21	Federal Income Tax	12,361,369	15,147,790	10,800,864
22	State Income Tax	3,466,896	4,248,382	3,029,233
23	Local Income Tax			

NOTES

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

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

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
							3
		See Note	1,386,960			17,246,153	4
							5
							6
-1,722,581	103,638					935,008	7
							8
-1,722,581	103,638		1,386,960			18,181,161	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
-1,722,581	103,638		1,386,960			18,181,161	19
							20
-1,345,281	80,938		1,083,172			14,198,904	21
-377,300	22,700		303,788			3,982,257	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) 12/31/2014	Year/Period of Report 2014/Q4
FOOTNOTE DATA			

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

228.3 - Adjustment due to ASC 715-60	(461,956)
182.3 - Adjustment due to ASC 740	(925,004)

Total	(1,386,960)
	=====

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

Deferred taxes related to CIP costs and mark to market accounting.

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

Pensions	(12,928,323)
Conservation Improvement Program - MN & SD - Net (BTL)	(935,006)
Wind Rider Revenue	139,008
Transmission Rider Revenue	(1,648,591)
Environmental Rider Revenue	(361,435)
Big Stone II Recovery Costs	56,270
Deferred State NOL's - Federal Haircut	(1,591,457)
Regulatory Adjustments	1,235,481
ASC 740 (SFAS 109) ADIT Credits - Non-Property	(2,147,108)
Total	(18,181,161)

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) 12/31/2014	Year/Period of Report End of <u>2014/Q4</u>
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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	1,959,732	190	410,483		1,549,249
2	ASC 740					
3						
4	Minnesota Portion of Gain on Sale of Wahpeton	111,528	407.4	5,580		105,948
5	Division Office					
6						
7	Derivatives - Mark to Market	122,986	175	1,524,532	1,658,652	257,106
8						
9	Margin Sharing - SD	37,781	See Note	81,182	67,947	24,546
10						
11	MN Transmission Revenue Rider	670,375	See Note	1,472,823	802,448	
12						
13	SD Transmission Revenue Rider				48,106	48,106
14						
15	ND Transmission Revenue Rider	215,473	See Note	742,814	527,341	
16						
17	ND Renewable Resource Revenue Rider	260,596	See Note	3,505,201	4,262,718	1,018,113
18						
19	MN Future Rate Case Expense Accrual	288,793			495,072	783,865
20						
21	ND Big Stone Plant II		See Note	85	147,445	147,360
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39	See Footnote 3 in Notes to Financial					
40	Statements for amortization periods.					
41	TOTAL	3,667,264		7,742,700	8,009,729	3,934,293

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) 12/31/2014	Year/Period of Report 2014/Q4
FOOTNOTE DATA			

Schedule Page: 278 Line No.: 9 Column: c

Accounts were 440, 442, 444, and 445.

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

Accounts were 440, 442, 444, and 445.

Schedule Page: 278 Line No.: 15 Column: c

Accounts were 440, 442, 444, and 445.

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

Accounts were 440, 442, 444, and 445.

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

Accounts were 440, 442, 444, and 445.

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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) 12/31/2014	Year/Period of Report End of 2014/Q4
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ELECTRIC OPERATING REVENUES (Account 400)

- The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
- Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
- Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
- If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
- Disclose amounts of \$250,000 or greater in a footnote for accounts 451, 456, and 457.2.

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	119,730,343	113,434,253
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	136,930,327	125,635,483
5	Large (or Ind.) (See Instr. 4)	95,036,889	79,327,693
6	(444) Public Street and Highway Lighting	3,629,391	3,427,477
7	(445) Other Sales to Public Authorities	3,120,689	2,768,207
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	358,447,639	324,593,113
11	(447) Sales for Resale	11,159,834	14,846,056
12	TOTAL Sales of Electricity	369,607,473	339,439,169
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	369,607,473	339,439,169
15	Other Operating Revenues		
16	(450) Forfeited Discounts	628,802	592,316
17	(451) Miscellaneous Service Revenues	416,052	415,299
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	516,573	472,741
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	8,897,924	7,557,838
22	(456.1) Revenues from Transmission of Electricity of Others	22,068,639	16,224,445
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	32,527,990	25,262,639
27	TOTAL Electric Operating Revenues	402,135,463	364,701,808

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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
1,386,104	1,378,859	102,641	102,357	2
				3
1,688,771	1,659,629	26,651	26,576	4
1,551,483	1,382,443	56	54	5
26,218	26,062	402	406	6
42,486	40,548	590	595	7
				8
				9
4,695,062	4,487,541	130,340	129,988	10
775,834	1,732,210			11
5,470,896	6,219,751	130,340	129,988	12
				13
5,470,896	6,219,751	130,340	129,988	14

Line 12, column (b) includes \$ 429,831 of unbilled revenues.
Line 12, column (d) includes 11,383 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) 12/31/2014	Year/Period of Report 2014/Q4
FOOTNOTE DATA			

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

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

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

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

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

Description of Revenue	Current Year	Prior Year
All others (under \$250,000 each)	<u>\$416,052</u>	<u>\$415,299</u>
Total	\$416,052	\$415,299

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

Description of Revenue	Current Year	Prior Year
Sale of steam	\$ 2,444,647	\$ 2,414,903
Wind generation development	452,777	0
Integrated transmission deficiency payments	3,581,519	2,739,962
All others (under \$250,000 each)	2,418,981	2,402,973
	-----	-----
Total	\$ 8,897,924	\$ 7,557,838
	=====	=====

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential-440					
2	Residential Service					
3	9.01	953,406	94,403,319	96,747	9,855	0.0990
4						
5	Residential Service (Ctrld Demand					
6	9.02	166,836	12,315,531	6,288	26,532	0.0738
7						
8	Water Heating Ctrld (Off-Peak)					
9	14.01	40,049	3,022,749	16,304	2,456	0.0755
10				-16,304		
11	Controlled Service					
12	14.04,14.05,14.06,14.07	224,179	11,272,215	13,048	17,181	0.0503
13				-13,048		
14	Fixed Time of Delivery Service					
15	14.07	6,084	236,176	363	16,760	0.0388
16				-363		
17	Outdoor lighting-energy only					
18	11.03	58	5,301	8	7,250	0.0914
19				-8		
20	Outdoor Lighting					
21	11.04	3,921	552,227	343	11,431	0.1408
22				-343		
23	Small power producer rider					
24	12.01		292	7		
25				-7		
26	Conservation Imp Prog Rev		-1,053,224			
27	ND Big Stone Plant II Recvy		-66,122			
28	Environmental Rider Rev		-1,553,553			
29	Transmission Cost Recvy		1,662,929			
30	Renewable Resource Rider		-639,280			
31	Fuel Clause Adjustment Rec		257,888			
32	MN Rate Case Rev Reduction		-129,708			
33						
34	SUBTOTAL Billed	1,394,533	120,286,740	103,035	13,535	0.0863
35	Unbilled Rev (See Instr. 6)	-8,429	-556,397			0.0660
36	TOTAL - 440	1,386,104	119,730,343	103,035	13,453	0.0864
37						
38	Column D Lines 9,12,15,18,21&24					
39	customers are also served					
40	under other residential service.					
41	TOTAL Billed	4,683,679	358,017,808	133,441	35,099	0.0764
42	Total Unbilled Rev.(See Instr. 6)	11,383	429,831	0	0	0.0378
43	TOTAL	4,695,062	358,447,639	133,441	35,185	0.0763

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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	Commercial & Industrial-442					
2	General Service					
3	10.01,10.02	789,927	74,385,746	24,536	32,195	0.0942
4						
5	Farm Service					
6	9.03	81,072	6,977,851	2,807	28,882	0.0861
7						
8	Large General Service					
9	10.03	627,467	44,496,548	344	1,824,032	0.0709
10						
11	Real Time Pricing Rider					
12	14.02	41,613	1,784,738	1	41,613,000	0.0429
13						
14	Large Gen. Srv. (Time of Day)					
15	10.05	802,995	48,189,458	93	8,634,355	0.0600
16						
17	Large General Service Rider					
18	14.03	65,001	3,050,543	14	4,642,929	0.0469
19						
20	Water Heating Ctrlld (Off-Peak)					
21	14.01	2,172	155,127	526	4,129	0.0714
22				-526		
23	Controlled Service					
24	14.04,14.05,14.06,14.07	228,441	10,041,221	4,891	46,706	0.0440
25				-4,891		
26	Fixed Time of Delivery Service					
27	14.07	27,480	1,027,583	548	50,146	0.0374
28				-548		
29	Irrigation Service					
30	11.02	4,101	362,724	344	11,922	0.0884
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	4,683,679	358,017,808	133,441	35,099	0.0764
42	Total Unbilled Rev.(See Instr. 6)	11,383	429,831	0	0	0.0378
43	TOTAL	4,695,062	358,447,639	133,441	35,185	0.0763

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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	Commercial and Industrial - cntd					
2	Commercial Time of Use					
3	10.04	533,607	38,219,177	620	860,656	0.0716
4						
5	Outdoor Lighting - Energy Only					
6	11.03	2,032	167,486	253	8,032	0.0824
7				-253		
8	Outdoor Lighting					
9	11.04	14,417	1,896,380	262	55,027	0.1315
10				-262		
11	Standby Service - Option A Firm					
12	11.01	129	15,373	5	25,800	0.1192
13						
14	Small Power Producer Rider					
15	12.01		812	21		
16				-21		
17	Conservation Imp Prog Rev		-2,341,493			
18	ND Big Stone Plant II Recvy		-90,302			
19	Environmental Rider Rev		154,222			
20	Transmission Cost Recvy		3,617,404			
21	Renewable Resource Rider		-862,462			
22	Fuel Clause Adjustment Rec		95,095			
23	MN Rate Case Rev Reduction		-358,500			
24						
25	SUBTOTAL Billed	3,220,454	230,984,731	28,764	111,961	0.0717
26	Unbilled Rev (See Instr. 6)	19,800	982,485			0.0496
27	TOTAL - 442	3,240,254	231,967,216	28,764	112,650	0.0716
28						
29						
30						
31	Column D Lines 6,9 & 15					
32	customers are also served under					
33	other commerical service.					
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	4,683,679	358,017,808	133,441	35,099	0.0764
42	Total Unbilled Rev.(See Instr. 6)	11,383	429,831	0	0	0.0378
43	TOTAL	4,695,062	358,447,639	133,441	35,185	0.0763

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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					
3	11.03	7,544	603,984	265	28,468	0.0801
4				-265		
5	Outdoor lighting					
6	11.04	18,610	3,016,278	350	53,171	0.1621
7						
8	Conservation Imp Prog Rev		-15,181			
9	ND Big Stone Plant II Recvy		-836			
10	Environmental Rider Rev		-1,914			
11	Transmission Cost Recvy		23,627			
12	Renewable Resource Rider		-7,231			
13	Fuel Clause Adjustment Rec		5,564			
14	MN Rate Case Rev Reduction		-2,556			
15						
16	Subtotal billed	26,154	3,621,735	350	74,726	0.1385
17	Unbilled Revenue	64	7,656			0.1196
18	TOTAL - 444	26,218	3,629,391	350	74,909	0.1384
19						
20	Other Public Authority-445					
21	Pumping and Sirens					
22	11.05,11.06	42,538	3,115,665	1,292	32,924	0.0732
23	Conservation Imp Prog Rev		-30,412			
24	ND Big Stone Plant II Recvy		-1,170			
25	Environmental Rider Rev		-665			
26	Transmission Cost Recvy		46,867			
27	Renewable Resource Rider		-10,379			
28	Fuel Clause Adjustment Rec		9,004			
29	MN Rate Case Rev Reduction		-4,308			
30						
31	Subtotal	42,538	3,124,602	1,292	32,924	0.0735
32	Unbilled Revenue	-52	-3,913			0.0753
33	TOTAL - 445	42,486	3,120,689	1,292	32,884	0.0735
34						
35	Revenue from Fuel Adjustment					
36	Clause is reported in footnote.					
37						
38	Column D, Line 3					
39	customers are also served under					
40	other commercial service.					
41	TOTAL Billed	4,683,679	358,017,808	133,441	35,099	0.0764
42	Total Unbilled Rev.(See Instr. 6)	11,383	429,831	0	0	0.0378
43	TOTAL	4,695,062	358,447,639	133,441	35,185	0.0763

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FOOTNOTE DATA			

Schedule Page: 304.3 Line No.: 35 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	\$ 2,078,101
9.02	Residential service (control demand)	110,596
14.01	Water heating - controlled (off-peak)	128,539
14.04,14.05,14.06,14.07	Controlled service	152,300
14.07	Fixed time of delivery service	9,425
11.03	Outdoor lighting- energy only	(7)
11.04	Outdoor lighting	<u>9,233</u>
Total residential		\$ 2,488,187

Commercial and industrial - 442

10.01, 10.02	General service	\$ 1,432,536
9.03	Farm service	178,837
10.03	Large general service	(1,256,872)
14.02	Real time pricing rider	-
10.05	Large general service (time of day)	2,284,558
14.03	Large general service rider	109,255
14.01	Water heating - controlled (off-peak)	10,672
14.04,14.05,14.06,14.07	Controlled service	145,728
14.07	Fixed time of delivery service	29,633
11.02	Irrigation service	15,774
10.04	Commercial time of use	4,536,143
11.03	Outdoor lighting - energy only	5,133
11.04	Outdoor lighting	23,023
11.01	Standby service-option A firm	<u>(281)</u>
Total commercial and industrial		\$ 7,514,139

Streetlighting - 444

11.03	Outdoor lighting - energy only	\$ 13,972
11.04	Outdoor lighting	<u>42,519</u>
Total streetlighting		\$ 56,491

Other public authority - 445

11.05,11.06	Pumping and sirens	\$ 102,938
Total		<u>\$ 10,161,755</u>

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).

2. Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
 RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
 LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
 IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
 SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
 LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
 IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	RQ SALES					
2	Badger, SD	RQ	144	0.123	NA	NA
3	Newfolden, MN	RQ	174	0.531	NA	NA
4	Nielsville, MN	RQ	175	0.065	NA	NA
5	Shelly, MN	RQ	176	0.191	NA	NA
6						
7	NON-RQ SALES					
8	Minnesota Power	OS	V9	NA	NA	NA
9	Minnkota Power Cooperative	OS	V9	NA	NA	NA
10	Willmar Municipal Utilities	OS	V9	NA	NA	NA
11	RBC Capital Markets Corporation	OS	V9	NA	NA	NA
12	Midwest ISO Energy Market	OS	V9	NA	NA	NA
13						
14	Non-asset based sales	OS	V9	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

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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
453	6,669	15,471	4,106	26,246	2
2,760	30,356	94,451	25,350	150,157	3
163	4,666	5,986	1,448	12,100	4
909	12,959	31,070	8,208	52,237	5
					6
					7
6,450		272,940		272,940	8
6,800		320,800		320,800	9
4,000		184,000		184,000	10
423,650		-1,804,162		-1,804,162	11
330,649		10,919,093		10,919,093	12
					13
		1,026,423		1,026,423	14
4,285	54,650	146,978	39,112	240,740	
771,549	0	10,919,094	0	10,919,094	
775,834	54,650	11,066,072	39,112	11,159,834	

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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

Schedule Page: 310 Line No.: 14 Column: a

The Company records unrealized gains and losses of forward purchases and sales of energy. FERC Order No. 627 states that entities should record unrealized as well as realized gains and losses in accounts 421 and 426.5, as appropriate. This amount represents the non-asset based cost of forward energy sales.

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(Next page is 320)

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,642,981	1,718,195
5	(501) Fuel	64,548,005	69,634,963
6	(502) Steam Expenses	3,215,141	3,115,567
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,432,216	2,689,109
10	(506) Miscellaneous Steam Power Expenses	4,972,804	4,669,710
11	(507) Rents	448	535
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	76,811,595	81,828,079
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	773,644	758,277
16	(511) Maintenance of Structures	708,960	770,212
17	(512) Maintenance of Boiler Plant	7,236,561	6,172,350
18	(513) Maintenance of Electric Plant	4,755,818	1,139,056
19	(514) Maintenance of Miscellaneous Steam Plant	1,555,138	1,037,412
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	15,030,121	9,877,307
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	91,841,716	91,705,386
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	16,579	17,437
45	(536) Water for Power		
46	(537) Hydraulic Expenses	39,285	18,548
47	(538) Electric Expenses	46,139	99,185
48	(539) Miscellaneous Hydraulic Power Generation Expenses	22,345	37,330
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	124,348	172,500
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	4,134	3,187
54	(542) Maintenance of Structures	1,155	9,994
55	(543) Maintenance of Reservoirs, Dams, and Waterways	221,334	220,302
56	(544) Maintenance of Electric Plant	18,516	27,164
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,089	
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	247,228	260,647
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	371,576	433,147

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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	192,311	177,535
63	(547) Fuel	3,494,522	2,139,681
64	(548) Generation Expenses	2,493,274	2,392,405
65	(549) Miscellaneous Other Power Generation Expenses	620,963	558,504
66	(550) Rents	570,101	562,117
67	TOTAL Operation (Enter Total of lines 62 thru 66)	7,371,171	5,830,242
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	23,033	40,779
70	(552) Maintenance of Structures	37,245	39,732
71	(553) Maintenance of Generating and Electric Plant	790,197	692,029
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	142,449	57,897
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	992,924	830,437
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	8,364,095	6,660,679
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	65,848,281	52,005,874
77	(556) System Control and Load Dispatching	445,767	450,910
78	(557) Other Expenses	459,424	516,418
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	66,753,472	52,973,202
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	167,330,859	151,772,414
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	417,353	394,683
84			
85	(561.1) Load Dispatch-Reliability	83,412	75,910
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,446,095	2,542,773
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	721,548	
89	(561.5) Reliability, Planning and Standards Development	615,821	501,506
90	(561.6) Transmission Service Studies	782	3,843
91	(561.7) Generation Interconnection Studies	96	133
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	241,017	264,874
94	(563) Overhead Lines Expenses	336,332	256,921
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	13,428,393	9,892,519
97	(566) Miscellaneous Transmission Expenses	680,076	1,333,634
98	(567) Rents	38,264	57,166
99	TOTAL Operation (Enter Total of lines 83 thru 98)	19,009,189	15,323,962
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	263,031	177,027
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	55,519	116,690
104	(569.2) Maintenance of Computer Software	749,844	693,596
105	(569.3) Maintenance of Communication Equipment	91,291	114,946
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,088,198	1,096,529
108	(571) Maintenance of Overhead Lines	2,559,518	1,762,918
109	(572) Maintenance of Underground Lines		360
110	(573) Maintenance of Miscellaneous Transmission Plant	155	
111	TOTAL Maintenance (Total of lines 101 thru 110)	4,807,556	3,962,066
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	23,816,745	19,286,028

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)				
If the amount for previous year is not derived from previously reported figures, explain in footnote.				
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)	
113	3. REGIONAL MARKET EXPENSES			
114	Operation			
115	(575.1) Operation Supervision			
116	(575.2) Day-Ahead and Real-Time Market Facilitation	903,791	1,126,719	
117	(575.3) Transmission Rights Market Facilitation	298,199	277,392	
118	(575.4) Capacity Market Facilitation			
119	(575.5) Ancillary Services Market Facilitation			
120	(575.6) Market Monitoring and Compliance			
121	(575.7) Market Facilitation, Monitoring and Compliance Services			
122	(575.8) Rents			
123	Total Operation (Lines 115 thru 122)	1,201,990	1,404,111	
124	Maintenance			
125	(576.1) Maintenance of Structures and Improvements			
126	(576.2) Maintenance of Computer Hardware			
127	(576.3) Maintenance of Computer Software	280,611	355,415	
128	(576.4) Maintenance of Communication Equipment			
129	(576.5) Maintenance of Miscellaneous Market Operation Plant			
130	Total Maintenance (Lines 125 thru 129)	280,611	355,415	
131	TOTAL Regional Transmission and Market Op Exprns (Total 123 and 130)	1,482,601	1,759,526	
132	4. DISTRIBUTION EXPENSES			
133	Operation			
134	(580) Operation Supervision and Engineering	373,153	391,934	
135	(581) Load Dispatching	275,153	279,325	
136	(582) Station Expenses	231,893	221,746	
137	(583) Overhead Line Expenses	285,535	309,683	
138	(584) Underground Line Expenses	1,730,479	1,697,393	
139	(585) Street Lighting and Signal System Expenses	16,022		
140	(586) Meter Expenses	1,133,101	906,678	
141	(587) Customer Installations Expenses	196,638	191,354	
142	(588) Miscellaneous Expenses	3,136,552	2,911,754	
143	(589) Rents	237,624	238,522	
144	TOTAL Operation (Enter Total of lines 134 thru 143)	7,616,150	7,148,389	
145	Maintenance			
146	(590) Maintenance Supervision and Engineering	831,421	906,855	
147	(591) Maintenance of Structures			
148	(592) Maintenance of Station Equipment	752,806	998,178	
149	(593) Maintenance of Overhead Lines	4,287,091	4,539,291	
150	(594) Maintenance of Underground Lines	1,027,891	1,116,096	
151	(595) Maintenance of Line Transformers	92,316	59,066	
152	(596) Maintenance of Street Lighting and Signal Systems	1,060,301	1,082,338	
153	(597) Maintenance of Meters	729,783	744,889	
154	(598) Maintenance of Miscellaneous Distribution Plant	113,466	103,584	
155	TOTAL Maintenance (Total of lines 146 thru 154)	8,895,075	9,550,297	
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	16,511,225	16,698,686	
157	5. CUSTOMER ACCOUNTS EXPENSES			
158	Operation			
159	(901) Supervision	125,583	131,373	
160	(902) Meter Reading Expenses	5,939,271	6,059,234	
161	(903) Customer Records and Collection Expenses	6,178,613	6,141,525	
162	(904) Uncollectible Accounts	760,000	760,000	
163	(905) Miscellaneous Customer Accounts Expenses	354,679	330,156	
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	13,358,146	13,422,288	

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	811,827	751,283
168	(908) Customer Assistance Expenses	6,761,178	6,929,006
169	(909) Informational and Instructional Expenses	438,081	390,446
170	(910) Miscellaneous Customer Service and Informational Expenses	17,921	61,032
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	8,029,007	8,131,767
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	260,876	324,835
176	(913) Advertising Expenses	1,743	517
177	(916) Miscellaneous Sales Expenses	229,989	297,971
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	492,608	623,323
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	20,845,574	20,664,050
182	(921) Office Supplies and Expenses	8,117,224	6,856,713
183	(Less) (922) Administrative Expenses Transferred-Credit	1,550,302	1,765,173
184	(923) Outside Services Employed	1,208,582	1,218,312
185	(924) Property Insurance	1,987,665	1,842,172
186	(925) Injuries and Damages	2,352,407	2,027,359
187	(926) Employee Pensions and Benefits	2,684,087	3,027,596
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	1,052,165	1,087,449
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	473,030	361,179
192	(930.2) Miscellaneous General Expenses	1,374,483	1,341,268
193	(931) Rents	272,535	284,005
194	TOTAL Operation (Enter Total of lines 181 thru 193)	38,817,450	36,944,930
195	Maintenance		
196	(935) Maintenance of General Plant	2,969,643	2,578,021
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	41,787,093	39,522,951
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	272,808,284	251,216,983

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) 12/31/2014	Year/Period of Report 2014/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

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

\$675,907 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

\$713,545 of the year-to-date expense recorded in Accounts 561 and 569 is designated as Account 561.BA expense.

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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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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	EDF Trading North America	SF		100	NA	NA
2	Great River Energy	SF		100	NA	NA
3	Manitoba Hydro Electric Board	OS		NA	NA	NA
4	Northern States Power Company	OS		NA	NA	NA
5	Southern MN Municipal Power Agency	SF		75	NA	NA
6	Western Area Power Administration	OS		NA	NA	NA
7	Western Area Power Administration WEC	OS		NA	NA	NA
8	Beltrami Electric Cooperative	RQ		NA	NA	NA
9	Nodak Rural Electric Cooperative	RQ		NA	NA	NA
10	P K M Electric Cooperative	RQ		NA	NA	NA
11	Red Lake Rural Electric Cooperative	RQ		NA	NA	NA
12	Lake Region Rural Electric Cooperative	RQ		NA	NA	NA
13	Redwood Electric Cooperative	RQ		NA	NA	NA
14	Whetstone Valley Electric Cooperative	RQ		NA	NA	NA
	Total					

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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)	
			-112,000			-112,000	1
			990,000			990,000	2
9,600				122,060		122,060	3
171,200				129,377		129,377	4
			-140,625			-140,625	5
					46,008	46,008	6
29,870				993,192		993,192	7
65,808			550,417	3,315,486	61,231	3,927,134	8
8,377			102,522	479,253		581,775	9
8,426			94,753	435,235		529,988	10
7,223			85,288	355,711		440,999	11
70			679	6,781		7,460	12
521				23,486		23,486	13
11			325	81		406	14
2,272,541			1,704,949	64,036,093	107,239	65,848,281	

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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.

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

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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	Sioux Valley Energy	RQ		NA	NA	NA
2	Cass County Electric Cooperative	RQ		NA	NA	NA
3	Prairie Lakes Muni Waste	RQ		NA	NA	NA
4	Dakota Magic Casino	RQ		NA	NA	NA
5	Kindred School	RQ		NA	NA	NA
6	Valley Queen Cheese	OS		NA	NA	NA
7	Stevens Community Medical	OS		NA	NA	NA
8	City of Detroit Lakes	OS		NA	NA	NA
9	American Crystal Sugar	OS		NA	NA	NA
10	District 45 Methane	OS		NA	NA	NA
11	Dakota Wind Exchange	OS		NA	NA	NA
12	Hendricks Wind I	OS		NA	NA	NA
13	Borderline Wind	OS		NA	NA	NA
14	Univ. of MN - Morris	OS		NA	NA	NA
	Total					

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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.
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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$)(j)	Energy Charges (\$)(k)	Other Charges (\$)(l)	Total (j+k+l) of Settlement (\$)(m)	
1				55		55	1
			5,156			5,156	2
			15,400			15,400	3
			33,120			33,120	4
			42,020			42,020	5
			12,800			12,800	6
			23,760			23,760	7
1,111			1,334	1,667		3,001	8
11				108		108	9
9,503				424,776		424,776	10
147				4,950		4,950	11
2,352				105,829		105,829	12
2,334				70,018		70,018	13
5,207				286,367		286,367	14
2,272,541			1,704,949	64,036,093	107,239	65,848,281	

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	FPL Energy ND II, LLC	OS		NA	NA	NA
2	Langdon Wind, LLC	OS		NA	NA	NA
3	Turtle Mountain Community College	OS		NA	NA	NA
4	LacQui Parle School	OS		NA	NA	NA
5	Pembina Border Station	OS		NA	NA	NA
6	Lake Region State College	OS		NA	NA	NA
7	Ashtabula Wind III LLC	OS		NA	NA	NA
8	Ashtabula Wind III LLC - Curtailment	OS		NA	NA	NA
9	MN Co Generation	OS		NA	NA	NA
10	ND Co Generation	OS		NA	NA	NA
11	SD Co Generation	OS		NA	NA	NA
12						
13						
14						
	Total					

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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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)	
59,284				1,772,594		1,772,594	1
77,517				3,040,201		3,040,201	2
686				23,176		23,176	3
33				1,098		1,098	4
604				19,912		19,912	5
5,071				159,632		159,632	6
237,017				6,320,300		6,320,300	7
10,381				275,553		275,553	8
132				11,073		11,073	9
62				262		262	10
45				1,477		1,477	11
							12
							13
							14
2,272,541			1,704,949	64,036,093	107,239	65,848,281	

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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PURCHASED POWER (Account 555)
(Including power exchanges)

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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	Missouri River Energy Services RLA	OS		NA	NA	NA
2	RBC Capital Markets Corporation	OS		NA	NA	NA
3	Midwest ISO Energy Market	OS		NA	NA	NA
4						
5	Non-Asset Based Cost of Sales					
6	Miscellaneous Energy Market Changes					
7	Other ISO Energy Markets					
8						
9						
10						
11						
12						
13						
14						
	Total					

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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)	
-15,989				-573,000		-573,000	1
433,300				-3,558,401		-3,558,401	2
1,161,077				56,185,255		56,185,255	3
							4
-18,451				-6,668,142		-6,668,142	5
				-14,986		-14,986	6
				285,657		285,657	7
							8
							9
							10
							11
							12
							13
							14
2,272,541			1,704,949	64,036,093	107,239	65,848,281	

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) 12/31/2014	Year/Period of Report 2014/Q4
FOOTNOTE DATA			

Schedule Page: 326 Line No.: 1 Column: a
January through December 2014

Schedule Page: 326 Line No.: 2 Column: a
January through December 2014

Schedule Page: 326 Line No.: 5 Column: a
January through May 2014

Schedule Page: 326 Line No.: 6 Column: l
Load following charge

Schedule Page: 326 Line No.: 8 Column: l
Nomination charge

Schedule Page: 326.3 Line No.: 5 Column: a
The Company records unrealized gains and losses of forward purchases and sales of energy. FERC Order No. 627 states that entities should record unrealized as well as realized gains or losses in accounts 421 or 426.5, as appropriate. This amount represents the non-asset based cost of forward energy sales.

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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) 12/31/2014	Year/Period of Report End of 2014/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.

2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).

3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)

4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Badger, SD	Western Area Power Administration	Badger, SD	LFP
2	Newfolden, MN	Western Area Power Administration	Newfolden, MN	LFP
3	Nielsville, MN	Western Area Power Administration	Nielsville, MN	LFP
4	Shelly, MN	Western Area Power Administration	Shelly, MN	LFP
5	Fort Totten Indian Agency	Western Area Power Administration	Fort Totten, ND	LFP
6	State Development Center	Western Area Power Administration	Grafton, ND	LFP
7	North Dakota School for Deaf	Western Area Power Administration	Devils Lake, ND	LFP
8	North Dakota School of Forestry	Western Area Power Administration	Bottineau, ND	LFP
9	North Dakota College of Science	Western Area Power Administration	Wahpeton, ND	LFP
10	Turtle Mountain Indian Agency	Western Area Power Administration	Belcourt, ND	LFP
11	Oakes O&M Headquarters	Western Area Power Administration	Oakes, ND	LFP
12	Minnkota Power Cooperative, Inc.	Minnkota Power Cooperative, Inc.	Various Interconnects	OS
13		U.S. Bureau of Reclamation	Otter Tail Power Company	OS
14		Various Companies	Otter Tail Power Company	OS
15		Various Companies	Otter Tail Power Company	OS
16	Midwest Independent System Operator	Various Companies	Various Companies	OS
17	See Footnote			
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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		1,373	1,315	1
4	(1)	Newfolden, MN		3,019	2,822	2
4	(1)	Nielsville, MN		726	678	3
4	(1)	Shelly, MN		1,823	1,704	4
4	(1)	Fort Totten, ND		339	320	5
4	(1)	Grafton, ND		4,590	4,330	6
4	(1)	Devils Lake, ND		498	465	7
4	(1)	Bottineau, ND		1,209	1,130	8
4	(1)	Wahpeton, ND		8,804	8,267	9
4	(1)	Belcourt, ND		1,741	1,642	10
4	(1)	Oakes, ND		81	77	11
See Footnote	(1)	Various Interconnect		258,707	241,782	12
		(1)		8,293		13
		(1)		-54,914		14
		(1)		5,678		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	241,967	264,532	

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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.
9,355			9,355	1
26,538			26,538	2
8,085			8,085	3
16,602			16,602	4
1,431			1,431	5
23,647			23,647	6
5,848			5,848	7
11,184			11,184	8
94,867			94,867	9
27,662			27,662	10
2,009			2,009	11
	241,782		241,782	12
				13
				14
				15
		21,599,629	21,599,629	16
				17
				18
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				24
				25
				26
				27
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				30
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				32
				33
				34
227,228	241,782	21,599,629	22,068,639	

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) 12/31/2014	Year/Period of Report 2014/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: m
Midwest Independent System Operator Transmission
Schedule 1 Network = \$ 444,740
Schedule 1 Firm = \$ 38,158
Schedule 1 Non-firm = \$ 13,932

Schedule Page: 328 Line No.: 17 Column: a
Lines 1-10 Otter Tail Power Company wheels WAPA's portion of customers' load.
Line 11 Otter Tail Power Company wheels WAPA's total load to customer.
Line 12 Otter Tail Power Company wheels MPC's total load to various interconnects.
Lines 13-15 contain losses and regulation that result from interconnects with various companies in the integrated system.

Schedule Page: 328 Line No.: 17 Column: f
(1) Various points of interconnect in the integrated system in column f, lines 1-12 and column g, lines 13-15.

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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					3,268,144	3,268,144
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL						3,268,144	3,268,144

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) 12/31/2014	Year/Period of Report 2014/Q4
FOOTNOTE DATA			

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

Charges in line 1 are for Midwest Independent System Operator Schedule 26 Network Upgrade charges to Otter Tail Power Company from the Midwest Independent System Operator Transmission Expansion Plan costs that were booked in 2014.

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	242,332
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	24,781
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	160,814
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < \$5,000	39,144
6	Director Fees and Expenses	601,074
7	Miscellaneous Labor Not Provided for Elsewhere	294,835
8	News Release Distribution - Sundog Interactive, Inc.	11,503
9		
10		
11		
12		
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44		
45		
46	TOTAL	1,374,483

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) 12/31/2014	Year/Period of Report End of <u>2014/Q4</u>
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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of acquisition adjustments)

- Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
- Report in Section 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.
- 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.
- If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			1,294,748		1,294,748
2	Steam Production Plant	10,035,676	23,035			10,058,711
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	432,848				432,848
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	12,096,069	42,605			12,138,674
7	Transmission Plant	5,283,461				5,283,461
8	Distribution Plant	10,437,274				10,437,274
9	Regional Transmission and Market Operation					
10	General Plant	2,716,901				2,716,901
11	Common Plant-Electric					
12	TOTAL	41,002,229	65,640	1,294,748		42,362,617

B. Basis for Amortization Charges

The \$1,294,748 is amortization of:

Franchises and Consents (302)

\$41,845 for hydro plant licenses with a remaining life of 7.92 years at a 3.21% rate.

Miscellaneous Intangible Plant (303)

\$1,252,903 for computer software with a 5-year service life at a 20% rate.

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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	4,131	41.58	-8.10	1.84	SQ	14.22
15	312	31,939	29.23	-8.10	3.46	SQ	14.23
16	314	11,683	27.02	-8.10	3.44	SQ	14.23
17	315	2,758	34.09	-8.10	2.65	SQ	14.22
18	316	1,014	29.91	-7.90	3.46	SQ	14.23
19							
20	Hoot Lake Plant						
21	311 - Units 2, 3	482	35.48	-14.30	2.99	SQ	7.42
22	312 - Units 2, 3	10,467	17.98	-14.30	5.92	SQ	7.43
23	314 - Units 2, 3	1,120	29.87	-14.30	3.33	SQ	7.43
24	315 - Units 2, 3	462	43.52	-14.30	4.18	SQ	7.42
25	316 - Units 2, 3	360	16.67	-14.20	6.47	SQ	7.43
26							
27	Coyote Plant						
28	311	10,278	52.78	-8.70	1.45	SQ	27.41
29	312	32,038	49.35	-8.70	1.61	SQ	27.42
30	314	12,205	40.71	-8.70	2.18	SQ	27.44
31	315	4,401	47.92	-8.70	1.67	SQ	27.42
32	316	989	41.15	-8.40	2.20	SQ	27.44
33							
34	STEAM PROD	124,327					
35							
36	HYDRO PRODUCTION						
37	Hoot Lake Hydro						
38	331	1	59.08		0.24	SQ	8.40
39	332	53	29.78		2.12	SQ	8.40
40	333	13	35.86		1.44	SQ	8.40
41	334	6	30.50		1.98	SQ	8.40
42	335	46	8.90		11.24	SQ	8.41
43							
44	Wright Hydro						
45	331	5	30.51		2.99	SQ	8.40
46	332	154	19.45		4.79	SQ	8.41
47	333	94	18.72		4.88	SQ	8.41
48	334	87	17.70		5.14	SQ	8.41
49	335	79	12.20		8.13	SQ	8.41
50							

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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	2	38.36		2.39	SQ	8.40
14	332	205	13.36		7.13	SQ	8.41
15	333	89	15.81		6.64	SQ	8.41
16	334	48	17.97		5.69	SQ	8.41
17	335	62	8.90		11.80	SQ	8.41
18							
19	Dayton Hollow Hydro						
20	331	14	9.91		10.44	SQ	8.41
21	332	1,098	13.34		10.19	SQ	8.41
22	333	125	14.11		6.54	SQ	8.41
23	334	74	21.22		4.56	SQ	8.41
24	335	102	8.92		10.88	SQ	8.41
25							
26	Taplin Gorge Hydro						
27	331	3	73.76		0.91	SQ	8.39
28	332	314	16.25		6.19	SQ	8.41
29	333	1	81.33		0.79	SQ	8.39
30	334	20	22.05		3.98	SQ	8.41
31	335	75	11.71		8.61	SQ	8.41
32							
33	Bemidji Hydro						
34	331	131	13.13		7.80	SQ	8.41
35	332	554	15.27		8.21	SQ	8.41
36	333	157	19.53		5.78	SQ	8.41
37	334	3	72.85		5.78	SQ	8.39
38	335	1	11.84		9.65	SQ	8.41
39							
40	HYDRO PROD	3,616					
41							
42	OTHER PRODUCTION						
43	Jamestown Peaking #1						
44	341	94	33.60	-1.40	3.36	SQ	10.35
45	342	230	17.07	-1.40	5.98	SQ	10.36
46	343	640	32.72	-1.40	2.29	SQ	10.35
47	345	50	46.65	-1.40	3.23	SQ	10.35
48	346	37	19.55	-1.40	5.56	SQ	10.36
49							
50							

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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	59	37.50	-2.40	2.72	SQ	10.35
14	342	99	28.17	-2.40	3.14	SQ	10.36
15	343	475	38.99	-2.40	1.68	SQ	10.35
16	345	47	41.77	-2.40	1.46	SQ	10.35
17	346	3	38.75	-2.40	1.47	SQ	10.35
18							
19	Jamestown Peaking #2						
20	341	15	16.97	-1.40	6.06	SQ	10.36
21	342	8	28.36	-1.40	2.33	SQ	10.35
22	343	630	37.77	-1.40	1.74	SQ	10.35
23	345	38	15.32	-1.40	5.50	SQ	10.36
24	346	5	37.00	-1.40	4.56	SQ	10.35
25							
26	Fergus Falls Ctrl Ctr						
27	343	290	33.85		2.87	SQ	17.10
28							
29	Solway Combust Turbine						
30	341	2,965	33.41	-0.40	2.83	SQ	24.67
31	342	696	33.29	-0.40	2.83	SQ	24.67
32	343	14,689	33.46	-0.40	2.81	SQ	24.67
33	345	861	33.57	-0.40	2.80	SQ	24.67
34	346	236	32.53	-0.40	2.95	SQ	24.67
35							
36	Langdon Wind Energy						
37	341	1,900	24.26	-1.50	4.10	SQ	19.02
38	344	53,187	24.19	-1.50	4.14	SQ	19.02
39	345	5,976	24.18	-1.50	4.21	SQ	19.02
40	346	19	19.89	-1.50	5.07	SQ	19.02
41							
42	Ashtabula Wind Energy						
43	341	2,602	24.24	-1.20	4.07	SQ	19.97
44	344	86,177	24.23	-1.20	4.10	SQ	19.97
45	345	5,132	24.24	-1.20	4.09	SQ	19.97
46	346	27	20.45	-1.20	4.87	SQ	19.97
47							
48							
49							
50							

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) 12/31/2014	Year/Period of Report End of <u>2014/Q4</u>
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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	1,887	24.23	-2.00	4.08	SQ	20.92
14	344	54,870	24.22	-2.00	4.11	SQ	20.92
15	345	4,074	24.23	-2.00	4.08	SQ	20.92
16	346	19	21.40	-2.00	4.62	SQ	20.92
17							
18	OTHER PROD	238,037					
19							
20	TRANSMISSION PLANT						
21	350.1	2,904			1.43		70.00
22	353	59,418	65.14	-5.00	1.53	R1	53.06
23	354	9,842	70.00	-10.00	2.37	R5	37.90
24	355	51,211	70.31	-50.00	1.87	R2	55.58
25	356	47,038	70.25	-30.00	1.64	R2	53.25
26	358	8	41.13	-5.00	1.43	S4	10.86
27	SUBTOTAL	170,421					
28							
29	DISTRIBUTION PLANT						
30	362	51,638	40.64	5.00	2.10	SC	32.22
31	364	30,028	68.07	-75.00	2.47	R3	48.68
32	365	10,839	65.20	-100.00	2.77	R2.5	44.33
33	367	34,494	39.88	-5.00	2.31	R4	24.81
34	368	68,256	40.15	50.00	1.25	R2.5	28.19
35	369	-1,537	55.18	-150.00	4.10	S5	33.52
36	369.1	21,616	45.11	-20.00	2.57	R4	30.89
37	370	15,086	29.93		3.18	L0.5	20.64
38	370.1	3,865	12.14		10.03	R5	4.42
39	370.2	8	5.00		20.00	SQ - Amortized	1.00
40	371.2	3,206	23.23	10.00	3.80	L0	17.10
41	373	2,220	22.46	-5.00	3.29	L0.5	15.43
42	SUBTOTAL	239,719					
43							
44	GENERAL PLANT						
45	390	14,878	47.47	10.00	2.06	R1.5	31.91
46	390.1	3,039	35.36	51.20	0.24	SQ	17.10
47	390.2	314	37.62	38.60	-0.01	SQ	12.29
48	390.3	1,914	51.56	95.50	-2.17	SQ	21.81
49	391	558	15.00		6.67	SQ - Amortized	5.53
50	391.1	403	10.00		10.00	SQ - Amortized	4.83

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	391.2	151	10.00		10.00	SQ - Amortized	3.15
14	391.5	1,893	5.00		20.00	SQ - Amortized	2.51
15	391.6	750	5.00		20.00	SQ - Amortized	2.32
16	392	14,445					
17	Aircraft	1,025	7.00	39.00			
18	Autos		5.00	15.00			
19	Light Trucks		10.00	10.00			
20	Heavy Trucks & Semi		10.00	15.00			
21	Tractors (includes		10.00	15.00			
22	Cranes)						
23	Trailers		15.00	10.00			
24	Portable Oil Purifier		10.00	20.00			
25	Trenchers		10.00	10.00			
26	Misc. Light Equipment		10.00	10.00			
27	Misc. Heavy Equipment		15.00	15.00			
28	394	2,229	15.00		6.67	SQ - Amortized	9.23
29	394.2	329	15.00		6.67	SQ - Amortized	9.50
30	395		15.00		6.67	SQ - Amortized	
31	396	378	25.93	20.00	2.74	L0	16.79
32	397	640	15.00		6.67	SQ - Amortized	8.94
33	397.1	878	10.00		10.00	SQ - Amortized	5.61
34	397.2	2,143	15.00		6.67	SQ - Amortized	7.63
35	397.3	255	10.00		10.00	SQ - Amortized	6.35
36	397.4	1,101	40.23	5.00	2.14	R3	25.05
37	SUBTOTAL	47,323					
38							
39	TOTAL	823,443					
40							
41	SUBACCOUNTS USED						
42							
43							
44							
45							
46							
47							
48							
49							
50							

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Power Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2014	2014/Q4
FOOTNOTE DATA			

Schedule Page: 336.4 Line No.: 41 Column: a

SUBACCOUNTS USED

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

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

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

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

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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REGULATORY COMMISSION EXPENSES

- 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.
- 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	358,087		358,087	
3					
4	SD Public Utilities Commission	45,812		45,812	
5					
6	ND Public Service Commission	12,543		12,543	
7					
8	Federal Energy Regulatory Commission	297,323		297,323	
9					
10	Other Expenses:				
11	MN Public Utilities Commission:				
12	Miscellaneous		112,316	112,316	
13					
14	ND Public Service Commission:				
15	Miscellaneous		29,231	29,231	
16					
17	SD Public Utilities Commission:				
18	(SD Rate Case) EL10-011 (Amort Period 3 yrs)				6,069
19	Miscellaneous		49,247	49,247	
20					
21	FERC				
22	ER14-2850/ER14-2851 Integr IS Parties to SPP		79,155	79,155	
23	Miscellaneous		68,451	68,451	
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	713,765	338,400	1,052,165	6,069

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) 12/31/2014	Year/Period of Report End of <u>2014/Q4</u>
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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	358,087					2
							3
Electric	928	45,812					4
							5
Electric	928	12,543					6
							7
Electric	928	297,323					8
							9
							10
							11
Electric	928	112,316					12
							13
							14
Electric	928	29,231					15
							16
							17
Electric	928				6,069		18
Electric	928	49,247					19
							20
							21
Electric	928	79,155					22
Electric	928	68,451					23
							24
							25
							26
							27
							28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		1,052,165			6,069		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) 12/31/2014	Year/Period of Report End of 2014/Q4
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects. (Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).

2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:

(1) Generation

- a. hydroelectric
 - i. Recreation fish and wildlife
 - ii Other hydroelectric
- b. Fossil-fuel steam
- c. Internal combustion or gas turbine
- d. Nuclear
- e. Unconventional generation
- f. Siting and heat rejection

(2) Transmission

a. Overhead

b. Underground

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

B. Electric, R, D & D Performed Externally:

- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	Electric Utility R&D	
2		
3	PERFORMED INTERNALLY:	
4	Other	Miscellaneous
5	Other	Miscellaneous
6		
7	Sub-Total Performed Internally	
8		
9	PERFORMED EXTERNALLY:	
10		University of North Dakota
11		Mercer County
12		Chartwell Inc
13		E Source Companies Inc
14		
15		
16	Sub-Total Performed Externally	
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33	SUM OF ABOVE	
34		
35		
36		
37		

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

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

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

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

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

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

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
					1
					2
					3
18,142		920	18,142		4
18,529		930.2	18,529		5
					6
36,671			36,671		7
					8
					9
	7,500	506	7,500		10
	875	506	875		11
	7,857	930.2	7,857		12
	14,460	930.2	14,460		13
					14
					15
	30,692		30,692		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
36,671	30,692		67,363		32
					33
					34
					35
					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) 12/31/2014	Year/Period of Report End of 2014/Q4
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DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	9,587,501		
4	Transmission	4,233,401		
5	Regional Market	1,204,389		
6	Distribution	5,979,084		
7	Customer Accounts	8,690,198		
8	Customer Service and Informational	1,470,137		
9	Sales	446,649		
10	Administrative and General	22,366,898		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	53,978,257		
12	Maintenance			
13	Production	5,164,895		
14	Transmission	2,105,885		
15	Regional Market	17,651		
16	Distribution	5,837,366		
17	Administrative and General	1,913,178		
18	TOTAL Maintenance (Total of lines 13 thru 17)	15,038,975		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	14,752,396		
21	Transmission (Enter Total of lines 4 and 14)	6,339,286		
22	Regional Market (Enter Total of Lines 5 and 15)	1,222,040		
23	Distribution (Enter Total of lines 6 and 16)	11,816,450		
24	Customer Accounts (Transcribe from line 7)	8,690,198		
25	Customer Service and Informational (Transcribe from line 8)	1,470,137		
26	Sales (Transcribe from line 9)	446,649		
27	Administrative and General (Enter Total of lines 10 and 17)	24,280,076		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	69,017,232		69,017,232
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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)	69,017,232		69,017,232
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	13,567,720		13,567,720
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	13,567,720		13,567,720
72	Plant Removal (By Utility Departments)			
73	Electric Plant	653,335		653,335
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	653,335		653,335
77	Other Accounts (Specify, provide details in footnote):			
78	Fuel Stock (151)	50,940		50,940
79	Miscellaneous Deferred Debits (186)	1,128,457		1,128,457
80	Other Electric Revenue (456)	519,826		519,826
81	Expenses of Nonutility Operations (417.1)	194,672		194,672
82	Expenses for Certain Civic, Political and Related Activity (4	88,451		88,451
83	Other Deductions (426.5)	120,846		120,846
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	2,103,192		2,103,192
96	TOTAL SALARIES AND WAGES	85,341,479		85,341,479

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	12/31/2014	2014/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) 12/31/2014	Year/Period of Report End of <u>2014/Q4</u>
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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					
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41					
42					
43					
44					
45					
46	TOTAL				

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

- (1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.
- (2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.
- (3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.
- (4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.
- (5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
- (6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year			Amount Sold for the Year		
		Number of Units (b)	Unit of Measure (c)	Dollars (d)	Usage - Related Billing Determinant		
					Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch				9,591,397	\$/MW-Hr	944,326
2	Reactive Supply and Voltage				3,966,143	\$/MW-Hr	592,781
3	Regulation and Frequency Response	42,987	\$/MW-Hr	30,521			
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)	42,987		30,521	13,557,540		1,537,107

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) 12/31/2014	Year/Period of Report 2014/Q4
FOOTNOTE DATA			

Schedule Page: 398 Line No.: 1 Column: d

Line 1 does not include \$15,487 of services purchased from WAPA, which was purchased with a "Unit of Measure" of \$/Schedule - Day.

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) 12/31/2014	Year/Period of Report End of <u>2014/Q4</u>
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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	874	6	12	873	1				
2	February	855	10	8	854	1				
3	March	834	3	12	833	1				
4	Total for Quarter 1	2,563			2,560	3				
5	April	699	2	8	698	1				
6	May	601	15	8	600	1				
7	June	590	27	14	589	1				
8	Total for Quarter 2	1,890			1,887	3				
9	July	679	21	14	678	1				
10	August	635	19	16	634	1				
11	September	593	8	17	592	1				
12	Total for Quarter 3	1,907			1,904	3				
13	October	721	31	9	720	1				
14	November	791	20	8	790	1				
15	December	881	1	8	880	1				
16	Total for Quarter 4	2,393			2,390	3				
17	Total Year to Date/Year	8,753			8,741	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) 12/31/2014	Year/Period of Report 2014/Q4
FOOTNOTE DATA			

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

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

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

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

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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)	4,695,062
3	Steam	2,944,038	23	Requirements Sales for Resale (See instruction 4, page 311.)	4,285
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	771,549
5	Hydro-Conventional	19,948	25	Energy Furnished Without Charge	4
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	13,795
7	Other	547,437	27	Total Energy Losses	276,704
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	5,761,399
9	Net Generation (Enter Total of lines 3 through 8)	3,511,423			
10	Purchases	2,272,541			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	241,967			
17	Delivered	264,532			
18	Net Transmission for Other (Line 16 minus line 17)	-22,565			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	5,761,399			

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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	830,499	289,951	874	6	1200
30	February	581,547	88,518	855	10	800
31	March	530,411	44,613	834	3	1200
32	April	406,480	45,352	699	2	800
33	May	417,714	62,705	601	15	800
34	June	396,541	48,496	590	27	1400
35	July	390,410	45,392	679	21	1400
36	August	398,882	14,598	635	19	1600
37	September	362,514	30,182	593	8	1700
38	October	425,580	44,052	721	31	900
39	November	463,544	43,050	791	20	800
40	December	557,277	14,640	881	1	800
41	TOTAL	5,761,399	771,549			

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) 12/31/2014	Year/Period of Report 2014/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.

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(Next page is 402)

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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 term 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)			
		Steam			Steam			
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)		Conventional			Conventional		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		1981			1975		
3	Year Originally Constructed		1981			1975		
4	Year Last Unit was Installed		144.90			223.15		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)		151			256		
6	Net Peak Demand on Plant - MW (60 minutes)		7526			8274		
7	Plant Hours Connected to Load		150			258		
8	Net Continuous Plant Capability (Megawatts)		150			258		
9	When Not Limited by Condenser Water		78			82		
10	When Limited by Condenser Water		933036398			1429642254		
11	Average Number of Employees		718662			374603		
12	Net Generation, Exclusive of Plant Use - KWh		33209982			21793456		
13	Cost of Plant: Land and Land Rights		128517639			119120146		
14	Structures and Improvements		1377063			869783		
15	Equipment Costs		163823346			142157988		
16	Asset Retirement Costs		1130.5959			637.0513		
17	Total Cost		575273			610338		
18	Cost per KW of Installed Capacity (line 17/5) Including		16223301			32907493		
19	Production Expenses: Oper, Supv, & Engr		0			0		
20	Fuel		1622964			593493		
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)		613038			841519		
25	Electric Expenses		582245			2530371		
26	Misc Steam (or Nuclear) Power Expenses		438			11		
27	Rents		0			0		
28	Allowances		274571			321711		
29	Maintenance Supervision and Engineering		271623			304959		
30	Maintenance of Structures		2081467			2481132		
31	Maintenance of Boiler (or reactor) Plant		260360			680680		
32	Maintenance of Electric Plant		392545			435309		
33	Maintenance of Misc Steam (or Nuclear) Plant		22897825			41707016		
34	Total Production Expenses		0.0245			0.0292		
35	Expenses per Net KWh							
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	767589	3690	0	933527	3139	0	
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	6888	140000	0	8293	140000	0	
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	20.349	124.026	0.000	34.833	136.206	0.000	
41	Average Cost of Fuel per Unit Burned	20.393	130.200	0.000	34.701	137.802	0.000	
42	Average Cost of Fuel Burned per Million BTU	1.480	22.143	0.000	2.092	23.436	0.000	
43	Average Cost of Fuel Burned per KWh Net Gen	0.017	0.000	0.000	0.023	0.000	0.000	
44	Average BTU per KWh Net Generation	11342.000	0.000	0.000	10751.000	0.000	0.000	

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

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

Plant Name: <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			41			21		6
	11503			109			86		7
	149			42			20		8
	149			42			20		9
	149			42			20		10
	33			1			0		11
	581359425			1073046			624669		12
	617367			24614			12339		13
	6132426			305657			229834		14
	57275167			7359869			3891658		15
	587343			0			0		16
	64612303			7690140			4133831		17
	502.8195			159.8449			171.5283		18
	343842			7732			933		19
	16651197			487054			266683		20
	0			0			0		21
	1007225			0			0		22
	0			0			0		23
	0			0			0		24
	970275			67907			22945		25
	1138031			42345			574		26
	0			0			0		27
	0			0			0		28
	177870			7710			1325		29
	115061			12296			2176		30
	2736006			0			0		31
	3813892			97152			45402		32
	710498			72			0		33
	27663897			722268			340038		34
	0.0476			0.6731			0.5443		35
Coal	Oil		Oil			Oil			36
Tons	Barrels		Barrels			Barrels			37
385795	2342	0	3733	0	0	2349	0	0	38
9198	140000	0	140000	0	0	140000	0	0	39
43.984	130.368	0.000	128.940	0.000	0.000	136.878	0.000	0.000	40
43.450	131.460	0.000	130.473	0.000	0.000	113.526	0.000	0.000	41
2.362	22.357	0.000	22.189	0.000	0.000	19.307	0.000	0.000	42
0.029	0.000	0.000	0.454	0.000	0.000	0.427	0.000	0.000	43
11503.000	0.000	0.000	20455.000	0.000	0.000	22112.000	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) 12/31/2014	Year/Period of Report End of <u>2014/Q4</u>
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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 term 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)	43	0			
7	Plant Hours Connected to Load	1338	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	42384648	0			
13	Cost of Plant: Land and Land Rights	89809	0			
14	Structures and Improvements	4411779	0			
15	Equipment Costs	24018209	0			
16	Asset Retirement Costs	0	0			
17	Total Cost	28519797	0			
18	Cost per KW of Installed Capacity (line 17/5) Including	640.8943	0			
19	Production Expenses: Oper, Supv, & Engr	4559	0			
20	Fuel	2740785	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	474651	0			
26	Misc Steam (or Nuclear) Power Expenses	78994	0			
27	Rents	10935	0			
28	Allowances	0	0			
29	Maintenance Supervision and Engineering	3833	0			
30	Maintenance of Structures	22773	0			
31	Maintenance of Boiler (or reactor) Plant	0	0			
32	Maintenance of Electric Plant	417674	0			
33	Maintenance of Misc Steam (or Nuclear) Plant	34988	0			
34	Total Production Expenses	3789192	0			
35	Expenses per Net KWh	0.0894	0.0000			
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas	Oil			
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MMBTU	Barrels			
38	Quantity (Units) of Fuel Burned	452306	85	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	474090	140000	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	5.990	129.192	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	6.041	94.500	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	6.041	16.071	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.065	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	10683.000	0.000	0.000	0.000	0.000

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) 12/31/2014	Year/Period of Report 2014/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

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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	1.00	0.8	4,667	661,464
3	Wright	1922	0.40			1,773,429
4	Pisgah	1917	0.52	0.7	5,402	712,212
5	Dayton Hollow	1909	0.97	1.0	5,957	1,864,753
6	Taplin Gorge	1925	0.56	0.5	3,921	966,267
7	Bemidji	1941	0.74			1,346,162
8						
9	Internal Combustion:					
10	Fergus Falls Control Center	1995	1.83	2.0	22	591,638
11	Diesel Generators		2.26	1.6		
12						
13	Wind Turbine Plants					
14	Langdon	2007	40.50	40.5	152,877	79,083,954
15	Ashtabula	2008	48.00	48.3	169,562	116,465,960
16	Luverne	2009	49.50	49.9	180,894	72,730,299
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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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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
828,903	11,872		30,362	-		2
	9,121		51,285	-		3
950,883	7,904		41,069	-		4
1,805,182	8,629		42,206	-		5
1,802,736	8,296		21,040	-		6
	48,279		61,265	-		7
						8
						9
292,456	1,928		9,988	Oil		10
				Oil		11
						12
						13
1,954,766	979,685		5,596			14
2,412,902	964,347		153,057			15
1,458,632	923,185		165,424			16
						17
						18
						19
						20
						21
						22
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						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) 12/31/2014	Year/Period of Report 2014/Q4
FOOTNOTE DATA			

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

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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) 12/31/2014	Year/Period of Report End of 2014/Q4
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TRANSMISSION LINE STATISTICS

- Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
- 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.
- Report data by individual lines for all voltages if so required by a State commission.
- Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
- Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line 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.
- 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	Cedar Mountain	Helena	345.00	345.00	Steel Pole	70.00		1
2	Center	Maple River	345.00	345.00	Alum Tower	48.00		1
3	Chub Lake	Hampton	345.00	345.00	Steel Pole	17.00		1
4	Helena	Chub Lake	345.00	345.00	Steel Pole	22.00		1
5	Lyon County	Cedar Mountain	345.00	345.00	Steel Pole	47.00		1
6	Monticello	Quarry Sub	345.00	345.00	Steel Pole	29.00		1
7	St Cloud	Alexandria	345.00	345.00	Steel Pole	77.00		1
8								
9	Fergus Falls	Inman	230.00	230.00	Wood H	19.00		1
10	Fergus Falls	Wahpeton	230.00	230.00	Wood H	29.00		1
11	Wahpeton	Hankinson	230.00	230.00	Wood H	26.00		1
12	Hankinson	Forman	230.00	230.00	Wood H	37.00		1
13	Forman	Ellendale	230.00	230.00	Wood H	47.00		1
14	Audubon (W 1/10)	Badoura	230.00	230.00	Wood H	6.00		1
15	Audubon	Sheyenne	230.00	230.00	Wood H	42.00		1
16	Winger (E 1/3)	Wilton	230.00	230.00	Alum H	18.00		1
17	Grand Forks (M 1/3)	Winnipeg	230.00	230.00	Wood H	27.00		1
18	Big Stone (N 1/3)	Hankinson	230.00	230.00	Wood H	23.00		1
19	Big Stone (S 1/4)	Blair	230.00	230.00	Wood H	15.00		1
20	Harvey	Coal Creek	230.00	230.00	Wood H	75.00		1
21	Balta	Harvey	230.00	230.00	Wood H	22.00		1
22	Rugby	Balta	230.00	230.00	Steel H	18.00		1
23	Wilton	Cass Lake	230.00	230.00	Steel H	19.00		1
24	Cass Lake	Boswell	230.00	230.00	Steel H	51.00		1
25								
26		Total	115.00	115.00	Wood H	465.00		
27		Total	115.00	115.00	SWP	406.00		
28		Total	115.00	115.00	Steel Pole	4.00		
29		Total	69.00	69.00		209.00		
30								
31		Total	41.60	41.60	SWP	3,753.00		
32		Total	41.60	41.60	Underground	1.00		
33								
34								
35								
36					TOTAL	5,622.00		23

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) 12/31/2014	Year/Period of Report End of <u>2014/Q4</u>
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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)	
	572,855	6,019,266	6,592,121					1
		5,458,744	5,458,744					2
	288,169	2,316,636	2,604,805					3
	436,560	2,263,251	2,699,811					4
	359,676	3,632,293	3,991,969					5
	1,834,831	8,324,511	10,159,342					6
	2,336,975	23,743,174	26,080,149					7
								8
	6,339	1,980,466	1,986,805					9
	5,935	675,257	681,192					10
		475,142	475,142					11
		765,639	765,639					12
		803,584	803,584					13
		274,947	274,947					14
		991,046	991,046					15
		1,852,883	1,852,883					16
		913,195	913,195					17
		803,584	803,584					18
		867,131	867,131					19
		10,642,930	10,642,930					20
		4,277,028	4,277,028					21
		3,431,017	3,431,017					22
	489,732	4,363,737	4,853,469					23
	567,058	10,910,674	11,477,732					24
								25
	74,783	9,529,610	9,604,393					26
	393,467	26,501,982	26,895,449					27
	14,272	174,000	188,272					28
		6,361,375	6,361,375					29
								30
	4,953	97,789,826	97,794,779					31
		72,673	72,673					32
								33
				5,293,879	2,699,555	38,264	8,031,698	34
								35
	7,385,605	236,215,601	243,601,206	5,293,879	2,699,555	38,264	8,031,698	36

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	12/31/2014	2014/Q4
FOOTNOTE DATA			

Schedule Page: 422 Line No.: 34 Column: m
Columns m, n, o, and p detail by line not available.

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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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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 (f) to (g), 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	Added:						
2	St. Cloud	Alexandria	77.50	Single pole	6.00	1	1
3	Chub Lake	Hampton	17.30	Single pole	6.00	1	1
4	Helena	Chub Lake	21.80	Single pole	6.00	1	1
5	Helena	Cedar Mt	70.40	Single pole	6.00	1	2
6	Lyon County	Cedar Mt	47.30	Single pole	6.00	1	2
7	Cedar Mt	Franklin	4.30	Single pole	15.00	1	1
8							
9	Altered:						
10	Nunda 264	Rutland 266	2.00	3102	20.00	1	1
11	New Effington 464	New Effington Rural 462	3.00	3102	20.00	1	1
12	Johnson SW 587	East River Dumont 547	1.00	3102	22.00	1	1
13	Minnesota Industrial 226	Taunton 237	0.80	3102	24.00	1	1
14	Cyrus 522	Cyrus 521	3.00	3102	20.00	1	1
15	Green Valley 69 kV 590	Green Valley 244	4.60	3102	20.00	1	1
16	Sheyenne 230 kV S5F29	Mapleton 1212	7.80	3102	17.00	1	1
17	Pelican North Sub	180th Avenue	1.80	Single pole	17.00	1	14
18							
19							
20							
21							
22							
23							
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42							
43							
44	TOTAL		262.60		205.00	14	29

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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
954	ACSS	Delta	345	2,336,975	21,677,517	2,065,656		26,080,148	2
954	ACSS	Delta	345	288,169	1,825,244	491,392		2,604,805	3
954	ACSS	Delta	345	436,560	1,733,009	530,242		2,699,811	4
954	ACSS	Delta	345	572,855	4,539,993	1,479,273		6,592,121	5
954	ACSS	Delta	345	359,676	2,681,007	951,286		3,991,969	6
695-26/7	ACSS	Delta	115	14,272	134,068	39,932		188,272	7
									8
									9
3/0	ACSR	Vertical3102	41		60,263	49,307	14,381	123,951	10
1/0	ACSR-T2	Vertical3102	41		49,444	197,775	23,972	271,191	11
1/0	ACSR-T2	Vertical3102	41		129,973	52,859	-117,689	65,143	12
1/0	ACSR-T2	Vertical3102	41		71,708	67,481		139,189	13
266	ACSR-T2	Vertical3102	41		117,704	89,057		206,761	14
1/0R	ACSR-T2	Vertical3102	41	17,640	36,995	27,685		82,320	15
795 Drake	ACSR	Vertical3102	115		1,074,781	1,074,781		2,149,562	16
10RT2		3651	115	18,740	260,000		15,000	293,740	17
									18
									19
									20
									21
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				4,044,887	34,391,706	7,116,726	-64,336	45,488,983	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) 12/31/2014	Year/Period of Report End of 2014/Q4
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SUBSTATIONS

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

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	Transmission	230.00	115.00	13.80
4	Big Stone, SD Highway 12 - 63215	Transmission	115.00	41.60	
5	Browns Valley, MN - 230 kv (Peever) - 63325	Transmission	230.00	41.60	
6	Buffalo, ND - 345 kv - 63258	Transmission	345.00	115.00	43.00
7	Canby, MN - 115 kv - 63211	Transmission	115.00	41.60	
8	Cass Lake, MN - 230 kv - 620447	Transmission	230.00	115.00	13.80
9	Cass Lake, MN - 115 kv - 63347	Transmission	115.00	69.00	41.60
10	Clearbrook, MN - 115 kv - 63241	Transmission	115.00	41.60	
11	Crookston, MN - 115 kv - 63249	Transmission	115.00	41.60	
12	Devils Lake, ND - East 115 kv - 63265	Transmission	115.00	41.60	
13	Devils Lake, ND - SW 115 kv - 224	Transmission	115.00	41.60	
14	Donaldson, MN - 115 kv - 63255	Transmission	115.00	41.60	
15	Fergus Falls, MN - Hoot Lake 115 kv - 63223	Transmission	115.00	43.80	
16	Fertile, MN - 115 kv - 63250	Transmission	115.00	41.60	
17	Finley, ND - Pickert 115 kv - 711	Transmission	230.00	72.00	41.60
18	Forman, ND - Forman 230 kv - 63363	Transmission	230.00	115.00	41.60
19	Hensel, ND - 115 kv - 63157	Transmission	115.00	72.00	43.80
20	Hetland, SD - 115 kv - 63209	Transmission	115.00	41.60	
21	Jamestown, ND - 345 kv - 63369	Transmission	345.00	115.00	43.00
22	Jamestown, ND - Peaking Plant 115 kv - 63272	Transmission	115.00	41.60	
23	Maple River, ND - 345 kv - 66792	Transmission	345.00	230.00	13.80
24	Mapleton, ND - 115 kv - 63203	Transmission	115.00	41.60	
25	Marietta, MN - 115 kv - 63213	Transmission	115.00	41.60	
26	Northwoods, MN - 115kv - 63282	Transmission	115.00	41.60	
27	Oakes, ND - 230 kv - 63362	Transmission	230.00	41.60	
28	Oakes, ND - 230 kv - 63362 - Not In Service	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	Spiritwood, ND	Transmission	115.00	41.60	
34	Toronto, SD - 115 kv - 63210	Transmission	115.00	41.60	
35	Wahpeton Inventory (came from Cass Lake)	Transmission	115.00	69.00	41.60
36	Wilton, MN 230 kV - 63345	Transmission	230.00	115.00	13.80
37	Winger, MN 63238	Transmission	230.00	115.00	13.20
38	Subtotal:		5980.00	2418.40	391.60
39					
40	Transmission Subs Under 10,000 kva				

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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
26	1					5
112	1					6
27	1					7
187	1					8
40	1					9
13	1					10
95	2					11
34	1					12
57	1					13
20	2					14
30	1					15
10	1					16
60	1					17
140	1					18
55	1					19
45	1					20
224	2					21
56	1					22
672	2					23
20	1					24
10	1					25
13	1					26
34	1					27
		1				28
22	1					29
13	1					30
34	1					31
125	1					32
17	1					33
45	1					34
		1				35
140	1					36
140	1					37
2813	38	2				38
						39
						40

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SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Colgate	Transmission	69.00	43.80	12.50
2	Green Valley	Transmission	67.00	41.60	
3	Lake Preston	Transmission	69.00	44.00	
4	St Vincent	Transmission	69.00	41.60	
5	Wahpeton Inventory	Transmission	69.00	41.60	
6	Total:		6323.00	2631.00	404.10
7					
8	Distribution Subs 10,000 kva or higher				
9	Bemidji, MN 25th Street	Distribution	69.00	12.50	
10	Bemidji, MN Airport	Distribution	41.60	12.50	
11	Bemidji, MN Nymore	Distribution	69.00	12.50	
12	Bemidji, MN Industrial Park	Distribution	69.00	12.50	
13	Bottineau, ND Downtown - Not In Service	Distribution	41.60	12.50	
14	Casselton, ND	Distribution	41.60	12.50	
15	Casselton, ND Ethonal plant	Distribution	115.00	12.50	
16	Clearbrook, MN Pipeline	Distribution	115.00	4.16	
17	Cooperstown, ND	Distribution	41.60	12.50	
18	Crookston, MN Parkview	Distribution	41.60	12.50	
19	Crookston, MN South Main	Distribution	41.60	12.50	
20	Dawson, Mn Dawson Mills	Distribution	115.00	12.50	
21	Devils Lake, ND Downtown	Distribution	41.60	4.16	
22	Enderlin, ND	Distribution	115.00	12.50	
23	Fairmount, ND	Distribution	115.00	12.50	
24	Fergus Falls, MN Edgetown	Distribution	115.00	12.50	
25	Fergus Falls, MN Hoot Lake	Distribution	115.00	12.50	
26	Fergus Falls, MN South East	Distribution	115.00	12.50	
27	Gwinner, ND	Distribution	115.00	12.50	
28	Harvey, ND Northwest	Distribution	115.00	12.50	
29	Itasca, MN Minnesota Pipeline	Distribution	115.00	4.16	
30	Jamestown, ND Downtown	Distribution	115.00	12.50	
31	Jamestown, ND North	Distribution	115.00	12.50	
32	Jamestown, ND Potato	Distribution	115.00	12.50	
33	Jamestown, ND Southwest	Distribution	41.60	12.50	
34	Lake Norden, SD Dairy	Distribution	41.60	12.50	
35	Lisbon, ND Town	Distribution	115.00	12.50	
36	Mahnomen, MN	Distribution	115.00	12.50	
37	Milbank, SD Northwest	Distribution	41.60	12.50	
38	Milbank, SD South	Distribution	41.60	12.50	
39	Morris, MN Northeast	Distribution	41.60	12.50	
40	Morris, MN South	Distribution	115.00	12.50	

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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)	
6	1					1
7	1					2
9	1					3
8	1					4
		1				5
2843	42	3				6
						7
						8
20	1					9
14	1					10
14	1					11
11	1					12
	3					13
10	1					14
94	2					15
22	2					16
10	1					17
10	1					18
39	2					19
10	1					20
10	1					21
14	1					22
10	3					23
37	1					24
37	1					25
37	1					26
20	2					27
14	1					28
11	1					29
14	1					30
14	1					31
14	1					32
14	1					33
12	1					34
14	1					35
14	1					36
25	1					37
15	1					38
12	1					39
12	3					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) 12/31/2014	Year/Period of Report End of 2014/Q4
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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	Oakes, ND North	Distribution	41.60	12.50	
2	Parkers Prairie	Distribution	115.00	12.50	
3	Pelican Rapids, MN Turkey Plant	Distribution	41.60	12.50	
4	Perham, MN	Distribution	115.00	12.50	
5	Rosholt, SD	Distribution	41.60	12.50	
6	Rugby, ND South	Distribution	41.60	12.50	
7	Spiritwood, ND	Distribution	115.00	12.50	
8	Wahpeton Inventory	Distribution	115.00	12.50	
9	Wahpeton Inventory	Distribution	41.60	12.50	
10	Wahpeton Inventory	Distribution	41.60	4.16	
11	Wahpeton, ND North 115 kv - 63230	Distribution	115.00	12.50	
12	Wahpeton, ND Northwest	Distribution	41.60	12.50	
13	Wheaton, MN South	Distribution	115.00	12.50	
14	Distribution Subtotal:		3642.40	529.14	
15					
16	Distribution Under 10,000 kva	Distribution			
17	Distribution Total		3642.40	529.14	
18	Transmission From Above		6323.00	2631.00	404.10
19	Transmission & Distribution		9965.40	3160.14	404.10
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent Otter Tail Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2014	Year/Period of Report End of 2014/Q4
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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)	
10	3					1
10	1					2
10	1					3
28	2					4
10	1					5
10	1					6
84	2					7
		1				8
		4				9
		1				10
24	2					11
20	2					12
12	1					13
822	58	6				14
						15
						16
822	58	6				17
2843	42	3				18
3664	100	9				19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

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) 12/31/2014	2014/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.

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) 12/31/2014	Year/Period of Report End of 2014/Q4
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TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

- Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
- 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".
- Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	Non-power Goods or Services Provided by Affiliated			
2	Construction work in progress	Otter Tail Corporation	107	9,975
3	Insurance	Otter Tail Corporation	143	12,565
4	Civic and political activities	Otter Tail Corporation	186	1,250
5	Expenditures for certain civic, political and	Otter Tail Corporation	426.4	5,648
6	Dividends declared - common stock	Otter Tail Corporation	438	35,408,269
7	Corporate allocated A&G expense	Otter Tail Corporation	See Note	8,489,569
8				
9	Construction work in progress	Aevenia Inc	107	1,055,691
10	Steam power generation - maintenance of structures	Aevenia Inc	456	88,185
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Non-power Goods or Services Provided for Affiliate			
21	Printing, design & mailing services	Otter Tail Corporation	417	87,094
22	Other deductions	Otter Tail Corporation	426.5	506,342
23				
24	Printing, design & mailing services	Aevenia Inc	417	1,562
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2014	Year/Period of Report 2014/Q4
FOOTNOTE DATA			

Schedule Page: 429 Line No.: 7 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.: 7 Column: c

The following accounts were charged:

500	\$	3,879
501		1,593
506		4,719
907		1,336
908		1,313
920		4,402,720
921		2,219,007
923		339,102
924		2,522
925		190,289
926		2,219
928		11,059
930.1		10,833
930.2		895,820
931		73,656
935		329,502

Total \$ 8,489,569

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