

THIS FILING IS

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

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2014)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2014)
Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)



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

2 PU-13-201 Filed 05/01/2013 Pages: 232
2012 FERC 1 Report
Otter Tail Power Company

Exact Legal Name of Respondent (Company)

Otter Tail Power Company

Year/Period of Report

End of 2012/Q4

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

GENERAL INFORMATION

I. Purpose

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

II. Who Must Submit

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

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

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

III. What and Where to Submit

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

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

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

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

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

The CPA Certification Statement should:

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

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

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

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

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

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

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

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

IV. When to Submit:

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

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

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,144 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 150 hours per response.

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

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

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

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

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

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

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

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

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

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

General Penalties

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

REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Otter Tail Power Company		02 Year/Period of Report End of 2012/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) 12/31/2012

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) 04/09/2013
02 Title Chief Financial Officer		

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

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	Not applicable
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	Not applicable
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	Not applicable
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	Not applicable
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	Not applicable
25	Unrecovered Plant and Regulatory Study Costs	230	
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	Not applicable
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	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)	304	Not applicable
44	Sales of Electricity by Rate Schedules	310-311	
45	Sales for Resale	320-323	
46	Electric Operation and Maintenance Expenses	326-327	
47	Purchased Power	328-330	
48	Transmission of Electricity for Others	331	
49	Transmission of Electricity by ISO/RTOs	332	Not applicable
50	Transmission of Electricity by Others	335	
51	Miscellaneous General Expenses-Electric	336-337	
52	Depreciation and Amortization of Electric Plant	350-351	
53	Regulatory Commission Expenses	352-353	
54	Research, Development and Demonstration Activities	354-355	
55	Distribution of Salaries and Wages	356	
56	Common Utility Plant and Expenses	397	Not applicable
57	Amounts included in ISO/RTO Settlement Statements	398	
58	Purchase and Sale of Ancillary Services	400	
59	Monthly Transmission System Peak Load	400a	
60	Monthly ISO/RTO Transmission System Peak Load	401	Not applicable
61	Electric Energy Account	401	
62	Monthly Peaks and Output	402-403	
63	Steam Electric Generating Plant Statistics	406-407	
64	Hydroelectric Generating Plant Statistics	408-409	Not applicable
65	Pumped Storage Generating Plant Statistics	410-411	Not applicable
66	Generating Plant Statistics Pages	422-423	

Name of Respondent

Otter Tail Power Company

This Report Is:

(1) An Original

(2) A Resubmission

Date of Report

(Mo, Da, Yr)

12/31/2012

Year/Period of Report

End of 2012/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	424-425	
68	Transmission Lines Added During the Year	426-427	
69	Substations	429	
70	Transactions with Associated (Affiliated) Companies	450	
	<p>Stockholders' Reports Check appropriate box:</p> <p><input type="checkbox"/> Two copies will be submitted</p> <p><input type="checkbox"/> No annual report to stockholders is prepared</p>		

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) 12/31/2012	Year/Period of Report End of <u>2012/Q4</u>
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GENERAL INFORMATION

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

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

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

Minnesota - July 5, 1907

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

Not Applicable

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

Minnesota - Electric
North Dakota - Electric
South Dakota - Electric

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

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

Name of Respondent Otter Tail Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report <i>(Mo, Da, Yr)</i> 12/31/2012	Year/Period of Report End of <u>2012/Q4</u>
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CONTROL OVER RESPONDENT

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

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

CORPORATIONS CONTROLLED BY RESPONDENT

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

Definitions

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Not applicable			
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OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is \$50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.

2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	President and Chief Executive Officer, Utility	Charles S. MacFarlane	782,310
2			
3	Senior Vice President, Supply [1]	Ward L. Uggerud	238,805
4			
5	Vice President, IT and Special Projects [5]	Rodney C.H. Scheel	223,391
6			
7	Vice President, Customer Service	Mark H. Helland	218,449
8			
9	Vice President, Administration	Thomas R. Brause	253,102
10			
11	Chief Financial Officer	George D. Bell	236,026
12			
13	Vice President, Renewable Energy Development	Todd R. Wahlund	241,168
14	& Risk Management [3]		
15			
16	Vice President, Energy Supply [2]	Jan P. Rudolf	217,352
17			
18	Vice President, Asset Management [4]	Timothy J. Rogelstad	169,448
19			
20	Treasurer * **	Kevin G. Moug	679,189
21			
22	General Counsel and Assistant Secretary * **	George A. Koeck	575,048
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24	Secretary * **	Jennifer Smestad	200,533
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26	Assistant Treasurer * **	Suzanne Allen	185,634
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33			
34	[1] Retired effective 7/1/12		
35	[2] Appointed effective 5/1/12		
36	[3] Resigned effective 11/1/12		
37	[4] Appointed effective 12/1/12		
38	[5] Title change effective 12/1/12		
39			
40	* This individual is an employee of		
41	Otter Tail Corporation.		
42			
43	** Only a portion of this individual's salary is		
44	allocated to respondent.		

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 (1)	Fargo, North Dakota
3		
4	George A. Koeck, General Counsel & Assistant Secretary	Fargo, North Dakota
5		
6	Charles S. MacFarlane, President and CEO, Utility	Fergus Falls, Minnesota
7		
8	Kevin Moug, Treasurer	Fargo, North Dakota
9		
10	Shane Waslaski, Director (2)	Fargo, North Dakota
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47	(1) Appointed effective 1/17/2012	
48	(2) Appointed effective 10/15/2012	

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) 12/31/2012	Year/Period of Report End of 2012/Q4
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INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No
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1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	MISO's FERC Electric Tariff, Vol. 1	ER98-1438-000
2	MISO's FERC Electric Tariff, 3rd Revised Vol. 1	ER06-18-000
3	MISO's FERC Electric Tariff, 4th Revised Vol. 1	ER10-183
4	MISO's FERC Electric Tariff, 4th Revised Vol. 1	ER10-686
5	MISO's FERC Electric Tariff, 4th Revised Vol. 1	ER10-1791
6	MISO's FERC Electric Tariff, 4th Revised Vol. 1	ER10-1492
7	MISO's FERC Electric Tariff, 5th Revised Vol. 1	ER10-1997-000;001
8	MISO's FERC Electric Tariff, 5th Revised Vol. 1	ER11-28-000;001
9	MISO's FERC Electric Tariff, 5th Revised Vol. 1	ER11-3704
10	MISO's FERC Electric Tariff, 5th Revised Vol. 1	ER11-3279-000
11	MISO's FERC Electric Tariff, 5th Revised Vol. 1	ER12-297
12	MISO's FERC Electric Tariff, 5th Revised Vol. 1	ER12-312
13	MISO's FERC Electric Tariff, 5th Revised Vol. 1	ER12-334
14	MISO's FERC Electric Tariff, 5th Revised Vol. 1	ER12-450
15	MISO's FERC Electric Tariff, 5th Revised Vol. 1	ER12-715-000;002
16	MISO's FERC Electric Tariff, 5th Revised Vol. 1	ER12-1667
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Name of Respondent
Otter Tail Power Company

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

Date of Report
(Mo, Da, Yr)
12/31/2012

Year/Period of Report
End of 2012/Q4

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

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

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1					
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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
2		Form 1 schedule.		
3				
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Name of Respondent Otter Tail Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report 12/31/2012	Year/Period of Report End of <u>2012/Q4</u>
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

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

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2012	Year/Period of Report 2012/Q4
Otter Tail Power Company			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

1. None.
2. None.
3. None.
4. None.
5. None.
6. On October 29, 2012 the Company entered into a Second Amendment and Restated Credit Agreement (the Credit Agreement) which amended and restates the \$170 million OTP Credit Agreement dated as of March 3, 2011, which was set to expire on March 3, 2016. The Credit Agreement provides for a \$170 million line of credit that may be increased to \$250 million on the terms and subject to the conditions described in the Credit Agreement. This line is an unsecured revolving credit facility the Company can draw on 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 the Credit Agreement will bear interest at LIBOR plus 1.25%, subject to adjustment based on the ratings of the Company's senior unsecured debt. Under the Credit Agreement, the Company is required to pay the Banks' commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The Credit Agreement expires on October 29, 2017. As of December 31, 2012 there was no outstanding balance under the Credit Agreement.

The Credit Agreement contains a number of restrictions on the business of the Company, 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 Credit Agreement also contains affirmative covenants and events of default, as well as a financial covenant under which the Company may not permit the ratio of its "Interest-bearing Debt" to "Total Capitalization" (as defined in the Credit Agreement) to be greater than 0.60 to 1.00. The prior OTP Credit Agreement included similar covenants and events of default, but also included a financial covenant that is not included in the current Credit Agreement, under which the Company could not permit its "Interest and Dividend Coverage Ratio" (as defined in the prior OTP Credit Agreement) to be less than 1.50 to 1.00. The Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in the Company's credit ratings. The Company's obligations under the Credit Agreement are not guaranteed by any other party.

Minnesota Public Utilities Commission authorization given under Docket No. E-017/S-12-420 dated June 22, 2012.

7. None.
8. The average annual increase for nonunion employees was 2.93% effective April 1, 2012. Wages for Local Union 203, 239, 524 and 949 were increased by 3.5% effective for November 1, 2012. Wages for Local Union 1570 were increased by 3.0% effective September 1, 2012.
9. None.
10. Otter Tail Power Company is a subsidiary of Otter Tail Corporation. Cascade Investment L.L.C. owned approximately 9.6% of Otter Tail Corporation's outstanding common shares as of January 5, 2012. On July 13, 2012, Otter Tail Corporation retired early its \$50 million 8.895% unsecured senior note which had been held by Cascade Investment L.L.C. prior to the early retirement. Blackrock, Inc. holds approximately 5.74% of Otter Tail Corporation's outstanding common shares as of December 31, 2012. Vanguard Group, Inc. holds approximately 5.41% of Otter Tail Corporation's outstanding common shares as of December 31, 2012.
11. (Reserved.)

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Power Company	(1) <input checked="" type="checkbox"/> An Original	(Mo, Da, Yr)	
	(2) <input type="checkbox"/> A Resubmission	12/31/2012	2012/Q4
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

12. None.

13. Ward L. Uggerud, Senior Vice President, Supply, retired effective July 1, 2012. Jan P. Rudolf was appointed as Vice President, Energy Supply, effective May 1, 2012. Todd R. Wahlund, Vice President, Renewable Energy Development and Risk Management, resigned effective November 1, 2012. Timothy J. Rogelstad was appointed as Vice President, Asset Management, effective December 1, 2012. Rodney C.H. Scheel was appointed as Vice President, IT and Special Projects, effective December 1, 2012. On January 17, 2012 Edward J. McIntyre, President and Chief Executive Officer, Otter Tail Corporation, was appointed as director. On October 15, 2012 Shane Waslaski, Senior Vice President, Manufacturing and Infrastructure Platform, Otter Tail Corporation, was appointed as director.

14. Not applicable.

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200-201	1,423,302,739	1,372,534,123
3	Construction Work in Progress (107)	200-201	75,758,114	49,123,094
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		1,499,060,853	1,421,657,217
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	592,427,672	564,937,266
6	Net Utility Plant (Enter Total of line 4 less 5)		906,633,181	856,719,951
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)		906,633,181	856,719,951
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		516,451	430,180
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)		272,895	336,981
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		1,321,064	936,901
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		2,110,410	1,704,062
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		9,600	9,600
36	Special Deposits (132-134)		3,544,456	3,332,275
37	Working Fund (135)		19,055	19,055
38	Temporary Cash Investments (136)		12,304,382	14,476,654
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		18,604,824	17,862,585
41	Other Accounts Receivable (143)		6,498,327	7,764,422
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		880,577	862,296
43	Notes Receivable from Associated Companies (145)		1,408	1,040
44	Accounts Receivable from Assoc. Companies (146)		171,501	245,910
45	Fuel Stock (151)	227	11,011,796	11,388,594
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	16,967,307	16,046,997
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

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)		376,629	313,266
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)		17,275,878	17,693,982
62	Miscellaneous Current and Accrued Assets (174)		76,922	132,842
63	Derivative Instrument Assets (175)		501,974	3,803,333
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		136,338	9,130
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		86,619,820	92,237,389
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		3,584,585	3,818,988
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	3,862,580	5,752,477
72	Other Regulatory Assets (182.3)	232	152,408,690	139,206,387
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)		22,694	215,207
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	168,706	156,707
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)		2,246,564	2,526,360
82	Accumulated Deferred Income Taxes (190)	234	115,976,211	109,433,240
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		278,270,030	261,109,366
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		1,273,633,441	1,211,770,768

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) 12/31/2012	2012/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 in rate-making purposes, illustrated as follows for the current year.

December 31, 2011	313,266
January 31, 2012	1,882,007
February 29, 2012	1,550,905
March 31, 2012	1,359,520
April 30, 2012	2,675,859
May 31, 2012	2,441,906
June 30, 2012	2,230,153
July 31, 2012	1,995,229
August 31, 2012	1,760,434
September 30, 2012	1,553,884
October 31, 2012	1,319,063
November 30, 2012	1,084,576
December 31, 2012	376,629
13-month average for rate-making	1,580,264

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	229,861,391	209,861,391
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	135,107,683	131,049,415
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)	-1,627,095	-1,470,711
16	Total Proprietary Capital (lines 2 through 15)		363,342,479	339,440,595
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	320,135,000	320,195,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	15,500,000	15,500,000
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)		335,635,000	335,695,000
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		577,000	577,000
29	Accumulated Provision for Pensions and Benefits (228.3)		160,950,162	143,307,850
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)		5,206,496	4,807,704
35	Total Other Noncurrent Liabilities (lines 26 through 34)		166,733,658	148,692,554
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		47,153,222	41,335,715
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		1,201,276	922,398
41	Customer Deposits (235)		997,805	922,253
42	Taxes Accrued (236)	262-263	10,986,963	10,073,611
43	Interest Accrued (237)		4,588,505	4,589,576
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		1,177,800	1,103,099
48	Miscellaneous Current and Accrued Liabilities (242)		158,403	1,066,460
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		18,233,970	18,769,823
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		84,497,944	78,782,935
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	31,299,404	33,181,749
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	466,174	520,038
60	Other Regulatory Liabilities (254)	278	3,433,461	3,680,627
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		273,887,732	256,756,331
64	Accum. Deferred Income Taxes-Other (283)		14,337,589	15,020,939
65	Total Deferred Credits (lines 56 through 64)		323,424,360	309,159,684
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		1,273,633,441	1,211,770,768

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

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

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	342,731,195	333,968,506		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	204,599,030	197,144,092		
5	Maintenance Expenses (402)	320-323	26,276,567	27,194,580		
6	Depreciation Expense (403)	336-337	39,722,146	38,110,830		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	56,309	56,899		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	766,499	621,911		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	48,941	48,940		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		2,189,959	1,701,703		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		775,895	933,699		
13	(Less) Regulatory Credits (407.4)		480,913	1,091,478		
14	Taxes Other Than Income Taxes (408.1)	262-263	10,714,162	10,184,876		
15	Income Taxes - Federal (409.1)	262-263	-3,080,962	-2,865,466		
16	- Other (409.1)	262-263	-356,449	-1,365,810		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	32,664,385	28,721,355		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	22,785,018	18,345,834		
19	Investment Tax Credit Adj. - Net (411.4)	266	-2,091,006	-2,386,669		
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)		163	604		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		419,028	383,631		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		289,438,410	279,046,655		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		53,292,785	54,921,851		

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	
342,731,195	333,968,506					2
						3
204,599,030	197,144,092					4
26,276,567	27,194,580					5
39,722,146	38,110,830					6
56,309	56,899					7
766,499	621,911					8
48,941	48,940					9
2,189,959	1,701,703					10
						11
775,895	933,699					12
480,913	1,091,478					13
10,714,162	10,184,876					14
-3,080,962	-2,865,466					15
-356,449	-1,365,810					16
32,664,385	28,721,355					17
22,785,018	18,345,834					18
-2,091,006	-2,386,669					19
						20
						21
163	604					22
						23
419,028	383,631					24
289,438,410	279,046,655					25
53,292,785	54,921,851					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)		53,292,785	54,921,851		
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)		2,034,337	1,279,248		
34	(Less) Expenses of Nonutility Operations (417.1)		1,699,849	845,751		
35	Nonoperating Rental Income (418)		41,858	67,663		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		296,037	283,860		
38	Allowance for Other Funds Used During Construction (419.1)		1,167,824	861,119		
39	Miscellaneous Nonoperating Income (421)		13,396,103	18,663,785		
40	Gain on Disposition of Property (421.1)		5,949	42,958		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		15,242,259	20,352,882		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		5,422			
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		375,075	533,087		
46	Life Insurance (426.2)					
47	Penalties (426.3)			10,000		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		191,702	148,365		
49	Other Deductions (426.5)		8,538,555	13,777,319		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		9,110,754	14,468,771		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	5,392	5,184		
53	Income Taxes-Federal (409.2)	262-263	2,032,836	2,551,809		
54	Income Taxes-Other (409.2)	262-263	374,823	491,850		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	815,849	-203,607		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	612,190	831,132		
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)		2,616,710	2,014,104		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		3,514,795	3,870,007		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		18,514,348	18,241,770		
63	Amort. of Debt Disc. and Expense (428)		430,852	626,725		
64	Amortization of Loss on Reaquired Debt (428.1)		279,960	669,249		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)			234		
68	Other Interest Expense (431)		-234,487	1,335,615		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		656,067	628,141		
70	Net Interest Charges (Total of lines 62 thru 69)		18,334,606	20,245,452		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		38,472,974	38,546,406		
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)		38,472,974	38,546,406		

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		130,734,936	126,556,891
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)		38,472,974	38,546,406
17	Appropriations of Retained Earnings (Acct. 436)			
18	Excess hydro licensing amortization		-62,252	(52,144)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-62,252	(52,144)
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			-34,414,707	(34,316,217)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-34,414,707	(34,316,217)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		134,730,951	130,734,936
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39	Amortization reserve, federal (Account 215.1)		376,732	314,479
40				

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)		376,732	314,479
	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)		376,732	314,479
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		135,107,683	131,049,415
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)			

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	38,472,974	38,546,406
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	39,778,457	38,167,728
5	Amortization	1,246,291	1,297,576
6			
7			
8	Deferred Income Taxes (Net)	9,905,080	16,111,228
9	Investment Tax Credit Adjustment (Net)	-1,882,345	-11,763,064
10	Net (Increase) Decrease in Receivables	616,178	5,251,868
11	Net (Increase) Decrease in Inventory	-543,512	-755,014
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	5,715,009	2,848,825
14	Net (Increase) Decrease in Other Regulatory Assets	-11,312,406	-23,989,299
15	Net Increase (Decrease) in Other Regulatory Liabilities	-247,166	-15,120,249
16	(Less) Allowance for Other Funds Used During Construction	1,167,824	861,119
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	(Increase) decrease in noncurrent assets and deferred debits	140,233	4,044,012
19	Increase (decrease) in noncurrent liabilities and deferred credits	17,830,856	35,487,564
20	(Increase) decrease in other current assets	3,584,812	3,785,473
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	102,136,637	93,051,935
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-90,507,125	-58,599,962
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-86,271	329,452
30	(Less) Allowance for Other Funds Used During Construction	-1,167,824	-861,119
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-89,425,572	-57,409,391
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.

(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.

(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.

(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other: (Increase) decrease in funds on deposit with trustee	-212,181	635,875
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-89,637,753	-56,773,516
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		140,000,000
62	Preferred Stock		
63	Common Stock		
64	Other: debt issuance expense	-196,449	-1,651,372
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68	Other: proceeds from capital infusions	20,000,000	
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	19,803,551	138,348,628
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-60,000	-100,520,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		-25,314,076
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-34,414,707	-34,316,217
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-14,671,156	-21,801,665
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-2,172,272	14,476,754
87			
88	Cash and Cash Equivalents at Beginning of Period	14,505,309	28,555
89			
90	Cash and Cash Equivalents at End of period	12,333,037	14,505,309

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) 12/31/2012	Year/Period of Report 2012/Q4
Otter Tail Power Company			
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.: 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 12/31/2012	Year/Period of Report End of <u>2012/Q4</u>
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NOTES TO FINANCIAL STATEMENTS

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

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2012	Year/Period of Report 2012/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

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

	<u>2012</u>	<u>2011</u>
Cash Equivalents	\$ 12,304,382	\$ 14,476,654
Reconciliation	<u>2012</u>	<u>2011</u>
Cash - Account 131 (Line 35, Page 110)	\$ 9,600	\$ 9,600
Working Fund - Account 135 (Line 37, Page 110)	19,055	19,055
Cash Equivalent - Account 136 (Above)	<u>12,304,382</u>	<u>14,476,654</u>
	\$ 12,333,037	\$ 14,505,309

Otter Tail Power Company
Notes to Financial Statements
For the years ended December 31, 2012 and 2011

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 electric and nonelectric 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 (formerly known as Otter Tail Holding Company). 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 Midwest Independent Transmission System Operator (MISO) markets.

OTP provides electricity to more than 129,000 customers in a service area with outer boundaries that encompass a total expanse 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, 2012, OTP served 129,786 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>	2012	2011
Accounts Receivable	\$ 171	\$ 246
Accounts Payable	1,308	924
Long-Term Debt	15,500	15,500

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) 12/31/2012	Year/Period of Report 2012/Q4
Otter Tail Power Company			
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Operating Revenues	86	99
Other Operation and Maintenance Expenses	6,048	5,927
Interest Expense	1,103	1,103

The related party transactions predominately relate to electric sales to operating subsidiaries of Otter Tail Corporation and to the allocation of corporate overhead expenses and corporate aircraft usage to OTP. The corporate overhead expenses include such items as labor, professional services, office rent, subscriptions, information technology and general office expenses incurred by Otter Tail Corporation.

These expenses are allocated to OTP based on the type of expenditure using an allocation methodology as defined in 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 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 depreciation 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.

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 \$656,000 in 2012 and \$628,000 in 2011. 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 expense when incurred. 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. Such provisions as a percent of the average balance of depreciable electric utility property were 2.98% in 2012 and 2.94% in 2011. 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 Plants

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, 2012 and 2011 balance sheets:

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<i>(in thousands)</i>	2012	2011
Big Stone Plant:		
Electric Plant in Service	\$ 141,221	\$ 143,993
Construction Work in Progress	22,335	2,674
Accumulated Depreciation	(80,588)	(87,669)
Net Plant	\$ 82,968	\$ 58,998
Coyote Station:		
Electric Plant in Service	\$ 160,617	\$ 156,213
Construction Work in Progress	578	1,533
Accumulated Depreciation	(93,564)	(97,090)
Net Plant	\$ 67,631	\$ 60,656

OTP's share of direct revenue and expenses of the jointly owned plants 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). 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, have 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.

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, 2012 totaled \$8.3 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 impairment loss would be measured as the amount by which the carrying amount exceeds the fair value of the asset, where fair value is based on the discounted cash flows expected to be generated by the asset.

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. OTP amortizes investment tax credits over the estimated lives of related property. OTP records income taxes in accordance with ASC 740, *Income Taxes*, and has recognized in its

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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 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. OTP management believes all of OTP's deferred tax assets will be realized and, accordingly, has established no valuation allowance against OTP's deferred tax assets as of December 31, 2012.

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 (FCA), 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 FCA, for conservation program incentives and bonuses earned but not billed, and for renewable resource and transmission-related 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.

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 815, *Derivatives and Hedging*. 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 OTP's 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. OTP is required to mark to market these forward energy contracts and recognize changes in the fair value of these contracts as components of income over the life of the contracts. See note 4 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 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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<i>(in thousands)</i>	2012	2011
Cost Method:		
Economic Development Loan Pools	\$ 255	\$ 320
Equity Method:		
Partnerships	18	17
Total Investments	\$ 273	\$ 337

Fair Value Measurements

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

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 below as of December 31, 2012, are based on prices indexed to observable prices at an active trading hub. The range for Level 3 forward electric inputs was \$16 to \$48 per megawatt-hour. The weighted average price was \$35 per megawatt-hour. The level of deviation in the indexed prices of these contracts at their point of physical delivery from the observable prices for similar contracts at an active trading hub resulted in the contracts that were outstanding at both December 31, 2011 and December 31, 2012 being moved from Level 2 to Level 3 of the fair value hierarchy in 2012.

The following table presents changes in Level 3 forward energy contract derivative asset and liability fair valuations for the year ended December 31, 2012, the first year OTP's forward energy contracts were classified as Level 3 in the fair value hierarchy:

<i>(in thousands)</i>	Year ended December 31, 2012
Forward Energy Contracts - Fair Values Beginning of Year	\$ --
Transfers into Level 3 from Level 2	(15,884)
Less: Amounts Reversed on Settlement of Contracts Entered into in Prior Periods	5,135
Changes in Fair Value of Contracts Entered into in Prior Periods	(4,001)
Cumulative Fair Value Adjustments of Contracts Entered into in Prior Years at End of Period	(14,750)
Net Losses Recognized as Regulatory Assets on Contract Entered into in 2012	(3,032)
Forward Energy Contracts - Net Derivative Liability Fair Values End of Year	\$ (17,782)

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All Level 3 forward energy contracts in the table below are related to power purchase contracts where OTP intends to take physical delivery of the energy under the contract. When OTP takes physical delivery of the energy purchased under these contracts, the costs incurred will be recovered 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 to 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 2012 or 2011.

The following table presents, 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:

2012 (in thousands)	Level 1	Level 2	Level 3
Assets:			
Current Assets - Other:			
Forward Energy Contracts	\$ --	\$ 292	\$ 210
Forward Gasoline Purchase Contracts		136	
Total Assets	\$ --	\$ 428	\$ 210
Liabilities:			
Derivative Liabilities - Forward Energy Contracts	\$ --	\$ 242	\$ 17,992
Total Liabilities	\$ --	\$ 242	\$ 17,992

In 2012, OTP's investments in forward gasoline contracts were moved to level 2 of the fair value hierarchy.

2011 (in thousands)	Level 1	Level 2	Level 3
Assets:			
Current Assets - Other:			
Forward Energy Contracts		\$ 3,803	
Forward Gasoline Purchase Contracts	\$ 9		
Total Assets	\$ 9	\$ 3,803	
Liabilities:			
Derivative Liabilities - Forward Energy Contracts		\$ 18,770	
Total Liabilities		\$ 18,770	

The valuation methods and inputs used to develop the level 2 and 3 fair value measurements for forward energy contracts are described in note 4 to the financial statements.

Inventories

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

Supplemental Disclosures of Cash Flow Information

(in thousands)	As of December, 31	
	2012	2011
Noncash Investing Activities:		
Accounts Payable Outstanding Related to Capital Additions ¹	\$ 9,571	\$ 20,024

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

(in thousands)	2012	2011
Cash Paid During the Year for:		
Interest (net of amount capitalized)	\$ 17,960	\$ 18,930
Income Tax Payments (Refunds)	\$ 61	\$ (4)

New Accounting Standards

ASU 2013-02

In February 2013, the FASB issued ASU 2013-02, "Comprehensive Income (Topic 220): Reporting of Amounts Reclassified out of Accumulated Other Comprehensive Income," which requires entities to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, entities are required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under U.S. GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, entities are required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail on these amounts. This ASU is effective prospectively for reporting periods beginning after December 15, 2012. OTP is currently evaluating the impact of adopting this guidance.

2. Rate and Regulatory Matters

Minnesota

2010 General Rate Case Filing—OTP filed a general rate case on April 2, 2010 requesting an 8.01% base rate increase as well as a 3.8% interim rate increase. On May 27, 2010, the Minnesota Public Utilities Commission (MPUC) issued an order accepting the filing, suspending rates, and approving the interim rate increase, as requested, to be effective with customer usage on and after June 1, 2010. The MPUC held a hearing to decide on the issues in the rate case on March 25, 2011 and issued a written order on April 25, 2011. The MPUC authorized a revenue increase of approximately \$5.0 million, or 3.76% in base rate revenues, excluding the effect of moving recovery of wind investments to base rates. 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. Final rates went into effect October 1, 2011. The overall increase to customers was approximately 1.6% compared to the authorized interim rate increase of 3.8%, which resulted in an interim rate refund to Minnesota retail electric customers of approximately \$3.9 million in the fourth quarter of 2011. 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%. OTP's authorized rates of return are based on a capital structure of 48.28% long term debt and 51.72% common equity.

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: 12% by 2012; 17% by 2016; 20% by 2020 and 25% by 2025. Under certain circumstances and after consideration of costs and reliability issues, the MPUC may modify or delay implementation of the standards. OTP has acquired renewable resources and expects to acquire additional renewable resources in order to maintain compliance with the Minnesota renewable energy standard. OTP's

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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 MPUC issued an order on January 12, 2010 finding OTP's Luverne Wind Farm project eligible for cost recovery through the Minnesota Renewable Resource Adjustment (MNRRA). The 2010 annual MNRRA cost recovery filing was made on December 31, 2009. The MPUC approved OTP's petition for a 2010 MNRRA in the third quarter of 2010 with implementation effective September 1, 2010. The 2010 MNRRA was in place from September 1, 2010 through September 30, 2011 with a recovery of \$17.0 million.

The recovery of MNRRA costs was 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 has a regulatory asset of \$0.9 million for amounts eligible for recovery through the MNRRA rider that have not been billed to Minnesota customers as of December 31, 2012. A request for an updated rate to be effective October 1, 2012 was initially filed on June 28, 2012, followed by a revised filing on July 25, 2012. The filing, which is still under review, included a request to extend the period of the new rate for 18 months, which would reduce the current balance of unrecovered costs to zero. However, OTP now estimates the remaining unrecovered costs will be collected by the end of May 2013, so OTP is planning to make a supplemental filing to request that the current rate be retained until the remaining balance is recovered and that the MNRRA then be suspended.

Transmission Cost Recovery (TCR) Rider—In addition to the MNRRA rider, the Minnesota Public Utilities 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. 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.

OTP requested recovery of its transmission investments being recovered through its Minnesota TCR rider rate as part of its general rate case filed on April 2, 2010. In its April 25, 2011 general rate case order, the MPUC approved the transfer of transmission costs currently being recovered through OTP's Minnesota TCR rider to recovery in base rates. Final rates went into effect on October 1, 2011. OTP will continue to utilize the rider cost recovery mechanism until the remaining balance of the current transmission projects has been collected as well as to recover costs associated with approved regional projects. OTP filed a request for an update to its Minnesota TCR rider on October 5, 2010. The update to OTP's Minnesota TCR rider, approved by the MPUC on March 26, 2012, went into effect April 1, 2012.

In this TCR rider update, the MPUC addressed how to handle utility investments in transmission facilities that qualify for regional cost allocation under the MISO tariff. MISO regional cost allocation allows OTP to recover some of the costs of its transmission investment from the other MISO utilities. On March 26, 2012 the MPUC approved an all-in method for MISO regional cost allocations in which OTP's retail customers would be responsible for the entire investment OTP made with an offsetting credit for revenues received from other MISO utilities under the MISO tariff.

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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 August 22, 2012 the Minnesota Department of Commerce (MNDOC) filed comments and on August 24, 2012 the Minnesota Office of the Attorney General (MNOAG) filed comments. OTP filed reply comments on September 25, 2012 and supplemental comments on January 8, 2013 describing an agreement reached between OTP, the MNDOC and the MNOAG, to find eligible 3 of the 12 projects. MPUC approval of that agreement is pending. If approval is obtained to include additional projects in the rider, investment in the approved projects will be included in the next annual Minnesota TCR rider rate update filings and recovery of the investment will begin through the TCR rider rates if subsequently approved by the MPUC. Updated costs associated with existing projects within the Minnesota TCR rider will also be included in the next annual rider rate update filing. OTP has a regulatory liability of \$0.5 million as of December 31, 2012 for amounts billed to Minnesota customers that are subject to refund through the Minnesota TCR rider.

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 Next Generation Energy Act of 2007, passed by the Minnesota legislature in May 2007, transitions from a conservation spending goal to a conservation energy savings goal.

The 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.

In 2010, OTP recognized \$3.7 million in financial incentives relating to 2010, but reduced that amount by \$0.2 million in the fourth quarter of 2011. A written order was issued by the MPUC on January 11, 2012 approving the recovery of \$3.5 million for the 2010 MNCIP financial incentives. Beginning in January 2012, OTP's MNCIP Conservation Cost Recovery Adjustment (CCRA) increased from 3.0% to 3.8% for all Minnesota retail electric customers.

OTP recognized \$2.2 million in MNCIP financial incentives in 2011 relating to 2011 program results. On March 30, 2012 OTP submitted its annual 2011 financial incentive filing request for \$2.6 million and recognized an additional \$0.4 million of incentive related to 2011 in 2012. In December 2012, the MPUC approved the recovery of \$2.6 million in financial incentives for 2011 and also ordered a change in the MNCIP cost recovery methodology used by OTP from a percentage of a customer's bill to an amount per kwh consumed. The written order was issued on December 10, 2012. 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. The per-kwh cost allocation method is the principle method approved by the MPUC for other electric utilities in Minnesota. OTP recognized \$2.6 million of MNCIP financial incentives in 2012 relating to 2012 program results.

OTP has a regulatory asset of \$6.1 million for allowable costs and financial incentives that are eligible for recovery through the MNCIP rider that have not been billed to Minnesota customers as of December 31, 2012. OTP's Minnesota conservation recoverable costs and incentives totaled \$7.8 million in 2012, \$8.0 million in 2011 and \$8.6 million in 2010.

North Dakota

General Rate Case—On November 3, 2008 OTP filed a general rate case in North Dakota requesting an overall revenue increase of approximately \$6.1 million, or 5.1%, and an interim rate increase of approximately 4.1%, or \$4.8 million annualized, that went into effect on January 2, 2009. In an order issued by the North Dakota Public Service Commission

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(NDPSC) on November 25, 2009, OTP was granted an increase in North Dakota retail electric rates of \$3.6 million, or approximately 3.0%, which went into effect in December 2009. The NDPSC order authorizing an interim rate increase required OTP to refund North Dakota customers the difference between final and interim rates, with interest. OTP established a refund reserve for revenues collected under interim rates that exceeded the final rate increase. The refund reserve balance of \$0.9 million as of December 31, 2009 was refunded to North Dakota customers in January 2010. OTP deferred recognition of \$0.5 million in rate case-related filing and administrative costs that are subject to amortization and recovery over a three year period beginning in January 2010. As required by the NDPSC order in the OTP 2008 rate case, OTP submitted a filing for a request to remove the recovery of the costs associated with economic development in base rates in North Dakota. OTP proposed and the NDPSC approved an Economic Development Cost Removal Rider, under which all North Dakota customers will receive a credit of \$0.00025 per kwh. The monthly credit was effective with bills rendered on and after January 1, 2011.

Renewable Resource Cost Recovery Rider— On May 21, 2008 the NDPSC approved OTP’s request for a North Dakota Renewable Resource Cost Recovery Rider Adjustment (NDRRA) to enable 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. OTP included investment costs and expenses related to its 32 wind turbines at the Ashtabula Wind Energy Center that became commercially operational in November 2008 in its 2009 annual request to the NDPSC to increase the amount of the NDRRA. An NDRRA of \$0.0051 per kwh was approved by the NDPSC on January 14, 2009 and went into effect beginning with billing statements sent on February 1, 2009. Terms of the approved settlement provide for the recovery of accrued costs and returns on investments in renewable energy facilities under the NDRRA over a period of 48 months beginning in January 2010.

In a proceeding that was combined with OTP’s general rate case, the NDPSC reviewed whether to move the costs of the projects being recovered through the NDRRA into base rate cost recovery and whether to make changes to the rider. A settlement of the general rate case and the NDRRA reduced the NDRRA to \$0.00369 for the period from December 1, 2009 until the effective date for the next annual NDRRA filing, requested to be April 1, 2010. Because the 2008 annual NDRRA filing was combined with the general rate case proceedings (concluded in November 2009), the 2009 annual filing to establish the 2010 NDRRA (which includes cost recovery for OTP’s investment in its Luverne Wind Farm project) was delayed until December 31, 2009, with a requested effective date of April 1, 2010. Approval for implementation of an updated NDRRA was received in the third quarter of 2010 with implementation effective September 1, 2010.

The 2010 NDRRA was in place for the period of September 1, 2010 through March 31, 2012 with a recovery of \$15.6 million. On December 29, 2011 OTP submitted its annual update to the renewable rider with an April 1, 2012 effective date, which was approved by the NDPSC on March 21, 2012. The 2011 NDRRA has an expected recovery of \$10.1 million over the period April 1, 2012 through March 31, 2013. OTP has a regulatory asset of \$1.6 million for amounts eligible for recovery through the NDRRA rider that have not been billed to North Dakota customers as of December 31, 2012.

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. OTP filed a request for an initial North Dakota TCR rider with the NDPSC on April 29, 2011, which was approved by the NDPSC on April 25, 2012 to go into effect 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 currently in the rider, as well as proposing to include costs associated with ten additional projects for recovery within the rider, which the NDPSC approved on December 12, 2012 to go into effect January 1, 2013. OTP has a regulatory asset of \$0.1 million for amounts eligible for recovery through the North Dakota TCR rider that have not been billed to North Dakota customers as of December 31, 2012.

South Dakota

2010 General Rate Case Filing—On August 20, 2010 OTP filed a general rate case with the South Dakota Public Utilities

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Commission (SDPUC) requesting an overall revenue increase of approximately \$2.8 million, or just under 10.0%, which includes, among other things, recovery of investments and expenses related to renewable resources. On September 28, 2010 the SDPUC suspended OTP's proposed rates for a period of 180 days to allow time to review OTP's proposal. On January 19, 2011 OTP submitted a proposal to use current rate design to implement an interim rate in South Dakota to be effective on and after February 17, 2011. On January 26, 2011 OTP submitted an amended proposal to use a lower interim rate increase than originally proposed. At its February 1, 2011 meeting, the SDPUC approved OTP's request to implement interim rates using current rate design and the lower interim increase to be effective on and after February 17, 2011. On April 21, 2011, the SDPUC issued its written order approving an overall final revenue increase of approximately \$643,000 (2.32%) and an overall rate of return on rate base of 8.50% for the interim rates and final rates. 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. OTP billed \$570,000 to South Dakota customers under the TCR rider from December 1, 2011 through December 31, 2012 and had a regulatory asset of \$2,000 for amounts eligible for recovery through the South Dakota TCR rider that had not been billed to South Dakota customers as of December 31, 2012. On September 4, 2012 OTP filed its annual update to the South Dakota TCR rider rate. The request is currently under review by the SDPUC.

Energy Efficiency Plan—The SDPUC has encouraged all investor-owned utilities in South Dakota to be part of an Energy Efficiency Partnership to significantly reduce energy use. The plan is being implemented with program costs, carrying costs and a financial incentive being recovered through an approved rider.

On June 16, 2010 OTP filed a request with the SDPUC for approval of updates to its 2010 South Dakota Energy Efficiency Plan and approval for the continuation of the program in 2011. OTP requested increases in energy and demand savings goals and increases in related financial incentives for both 2010 and the requested 2011 program. In an order issued on July 27, 2010 the SDPUC approved OTP's request for updated energy, demand and participation goals for continuation of the program into 2011.

On April 29, 2011 OTP filed a request with the SDPUC for approval of a 2010 financial incentive of \$73,415 and a surcharge adjustment of \$0.00063 on South Dakota customers' bills. On May 25, 2011 OTP filed a request with the SDPUC for approval of updates to its 2012-2013 South Dakota Energy Efficiency Plan. The SDPUC approved the 2012-2013 plan with a maximum available incentive payment limited to 30% of the budget amount provided in the plan, or \$84,000.

Federal

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, which has 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 Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff). OTP was also authorized by the FERC to recover in its formula rate: (1) 100% of prudently incurred Construction Work in Progress (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 that OTP is investing in, including the Fargo Project, Bemidji Project and Brookings Project.

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On December 16, 2010, FERC approved the cost allocation for a new classification of projects in MISO called Multi-Value Projects (MVP). 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. The MVP cost allocation is currently being challenged at the United States Court of Appeals, Seventh Circuit.

Effective January 1, 2012, the FERC authorized OTP to recover 100% 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 Ellendale - Big Stone South MVP.

The Big Stone South - Brookings Project—OTP is jointly developing this project with Xcel Energy. MISO approved this project as an MVP under the MISO Tariff in December 2011. A Notice of Intent to Construct Facilities (NICF) was filed with the SDPUC on February 29, 2012. A portion of this line is anticipated to use previously obtained Big Stone II transmission route permits and easements and is expected to be in service in 2017. On July 31, 2012 the SDPUC approved the transfer of the Big Stone II transmission route permits to OTP. In December 2012, a request was filed with the SDPUC for recertification of a portion of the line route that was approved as part of the Big Stone II transmission development. OTP and Xcel Energy expect to make a joint route permit filing in the second quarter of 2013 for the remaining portion of the project.

The Ellendale - Big Stone South Project—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. This project will require regulatory approval from both the SDPUC and the NDPSC. Route permits are expected to be filed with the respective commissions in the third quarter of 2013.

Capacity Expansion 2020 (CapX2020)

CapX2020 is a joint initiative of eleven investor-owned, 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 kiloVolt (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 will be through the MISO Tariff (the Brookings Project as an MVP) and Minnesota, North Dakota and South Dakota TCR Riders.

The Fargo Project—All major permits have been received from state regulatory bodies and project agreements have been signed for the construction of the Fargo Project. The Monticello to St. Cloud portion of the Fargo Project was placed into service on December 21, 2011. Completion of all phases of the Fargo Project is scheduled for the first quarter of 2015.

The Brookings Project—All major permits have been received from state regulatory bodies and project agreements have been signed for the construction of the Brookings Project. The MISO granted unconditional approval of the Brookings Project as an MVP under the MISO Tariff in December 2011. This project will be placed in service in segments with the earliest segment being placed in service in the summer of 2013 and the last segment placed in service during the first quarter of 2015.

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

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Big Stone Air Quality Control System

The South Dakota Department of Environment and Natural Resources (DENR) determined that the Big Stone Plant is subject to Best Available Retrofit Technology (BART) requirements of the Clean Air Act (CAA), based on air dispersion modeling indicating that Big Stone's emissions reasonably contribute to visibility impairment in national parks and wilderness areas in Minnesota, North Dakota, South Dakota and Michigan. Under the U.S. Environmental Protection Agency's (EPA) regional haze regulations, South Dakota developed and submitted its implementation plan and associated implementation rules to the EPA on January 21, 2011. The DENR and EPA have agreed on non-substantive rule revisions, which were adopted by the Board of Minerals and Environment and became effective on September 19, 2011.

South Dakota developed and submitted its revised implementation plan and associated implementation rules to EPA on September 19, 2011. Under the South Dakota implementation plan, and its implementing rules, the Big Stone Plant must install and operate a new BART compliant air quality control system to reduce emissions as expeditiously as practicable, but no later than five years after the EPA's approval of South Dakota's implementation plan. On March 29, 2012 the EPA took final action to approve South Dakota's Regional Haze State Implementation Plan (SIP), finding that South Dakota's SIP submittal met all applicable regional haze regulations. The EPA's final approval of the SIP was effective on May 29, 2012.

On January 14, 2011 OTP filed a petition asking the MPUC for Advance Determination of Prudence (ADP) for the design, construction and operation of the BART compliant air quality control system at Big Stone Plant attributable to serving OTP's Minnesota customers. On December 20, 2011 the MPUC granted OTP's petition for ADP for the Big Stone Plant Air Quality Control System (AQCS). The MPUC written order was issued on January 23, 2012.

An application for an ADP filed by OTP with the NDPSC on May 20, 2011 was approved on May 9, 2012.

On March 30, 2012 OTP requested approval from the SDPUC for an environmental cost recovery rider to recover costs associated with the Big Stone Plant AQCS, with a proposed effective date of October 1, 2012. Information requests for this filing continue and OTP is currently awaiting SDPUC action. This rider is designed to recover the revenue requirements plus carrying charges of the Big Stone AQCS project while under construction as well as after completion of the project until placed into base rates through the filing of a rate case. For the initial period of October 1, 2012 through September 30, 2013, OTP is requesting revenue requirement recovery on expenditures incurred for the Big Stone Plant AQCS. The request is currently under review by the SDPUC.

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.

Minnesota—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 deemed recoverable from Minnesota ratepayers was \$3,199,000 (which excluded \$3,246,000 of project transmission-related costs). Because OTP will not earn a return on these deferred costs over the 60-month recovery period, the recoverable amount of \$3,199,000 was discounted to its present value of \$2,758,000 using OTP's incremental borrowing rate, in accordance with ASC 980, *Regulated Operations*, accounting requirements.

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On December 30, 2010 OTP filed a request for an extension of the Minnesota Route Permit for the Big Stone II transmission facilities. The request asks to extend the deadline for filing a CON for these transmission facilities until March 17, 2013. The April 25, 2011 MPUC order instructed OTP to transfer the \$3,246,000 Minnesota share of Big Stone II transmission costs to CWIP and to create a tracker account through which any over or under recoveries could be accumulated for refund or recovery determination in future rate cases as a regulatory liability or asset. If determined eligible for recovery under the FERC-approved MISO regional transmission tariff, the Minnesota portion of Big Stone II transmission costs and accumulated Allowance for Funds Used During Construction (AFUDC) will receive rate base treatment and recovery through the FERC-approved MISO regional transmission rates. Any amounts over or under collected through MISO rates will be reflected in the tracker account.

North Dakota—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 \$2,612,000 of project transmission-related costs) was determined to be \$10,080,000, of which \$4,064,000 represents North Dakota’s jurisdictional share.

OTP is including in its total recovery amount a carrying charge of approximately \$285,000 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 begins based on OTP’s average 2009 AFUDC rate of 7.65%. Because OTP will not earn a return on these deferred costs over the 36-month recovery period, the recoverable amount of \$4,349,000 was discounted to its present value of \$3,913,000 using OTP’s incremental borrowing rate, in accordance with ASC 980 accounting requirements. The North Dakota portion of Big Stone II generation costs is being 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 is \$1,053,000. OTP transferred the North Dakota share of Big Stone II transmission costs to CWIP, with such costs subject to AFUDC continuing from September 2009. If construction of all or a portion of the transmission facilities commences within three years of the NDPSC order approving the settlement agreement, the North Dakota portion of Big Stone II transmission costs and accumulated AFUDC shall be included in the rate base investment for these future transmission facilities. If construction is not commenced on any of the transmission facilities within three years of the NDPSC order approving the settlement agreement, OTP may petition the NDPSC to either continue accounting for these costs as CWIP or to commence recovery of such costs.

South Dakota—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 will be 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.

3. Regulatory Assets and Liabilities

As a regulated entity, OTP accounts for the financial effects of regulation in accordance with ASC 980, *Regulated Operations*. 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. The following regulatory assets reflect incurred costs eligible for recovery in future periods on which OTP will not earn a rate of return: Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits, the Accumulated ARO Accretion/Depreciation Adjustment, Debt

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Reacquisition Premiums, Big Stone II Unrecovered Project Costs - Minnesota, Deferred Income Taxes, the MISO Schedule 26 Transmission Cost Recovery Rider True-up, Big Stone II Unrecovered Project Costs - North Dakota, General Rate Case Recoverable Expenses and Deferred Holding Company Formation Costs. 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 regulatory assets represent amounts eligible for recovery under alternative revenue programs or on which OTP earns an incentive or rate of return: Conservation Improvement Program Costs and Incentives, North Dakota Renewable Resource Rider Accrued Revenues, Minnesota Renewable Resource Rider Accrued Revenues, Big Stone II Unrecovered Project Costs - South Dakota, North Dakota Transmission Rider Accrued Revenues and South Dakota Transmission Rider Accrued Revenue. The following table indicates the amount of regulatory assets and liabilities recorded on OTP's balance sheet:

<i>(in thousands)</i>	December 31, 2012	Remaining Recovery/ Refund Period
Regulatory Assets:		
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits	\$ 117,950	see note
Deferred Marked-to-Market Losses	17,999	72 months
Conservation Improvement Program Costs and Incentives	6,267	18 months
Accumulated ARO Accretion/Depreciation Adjustment	4,137	asset lives
Deferred Income Taxes	1,691	asset lives
North Dakota Renewable Resource Rider Accrued Revenues	1,619	15 months
MISO Schedule 26 Transmission Cost Recovery Rider True-up	1,352	see note
Minnesota Renewable Resource Rider Accrued Revenues	915	5 months
General Rate Case Recoverable Expenses	285	13 months
North Dakota Transmission Rider Accrued Revenues	110	12 months
Deferred Holding Company Formation Costs	82	18 months
South Dakota Transmission Rider Accrued Revenue	2	12 months
Total Regulatory Assets	\$ 152,409	
Regulatory Liabilities:		
Deferred Income Taxes	2,553	asset lives
Minnesota Transmission Rider Accrued Refund	489	12 months
Deferred Marked-to-Market Gains	217	68 months
Deferred Gain on Sale of Utility Property - Minnesota Portion	118	252 months
South Dakota - Nonasset-Based Margin Sharing Excess	56	12 months
Total Regulatory Liabilities	\$ 3,433	
Net Regulatory Asset Position	\$ 148,976	

<i>(in thousands)</i>	December 31, 2011	Remaining Recovery/ Refund Period
Regulatory Assets:		
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits	\$ 102,377	see notes
Deferred Marked-to-Market Losses	15,957	44 months
Conservation Improvement Program Costs and Incentives	7,442	18 months
Accumulated ARO Accretion/Depreciation Adjustment	3,662	asset lives

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Minnesota Renewable Resource Rider Accrued Revenues	2,767	33 months
Deferred Income Taxes	2,382	asset lives
North Dakota Renewable Resource Rider Accrued Revenues	2,110	24 months
General Rate Case Recoverable Expenses	1,006	25 months
North Dakota Transmission Rider Accrued Revenues	518	12 months
MISO Schedule 16 and 17 Deferred Administrative Costs - ND	343	11 months
MISO Schedule 26 Transmission Cost Recovery Rider True-up	252	12 months
Deferred Holding Company Formation Costs	138	30 months
South Dakota - Asset-Based Margin Sharing Shortfall	138	2 months
South Dakota Transmission Rider Accrued Revenues	114	12 months
Total Regulatory Assets	\$ 139,206	
Regulatory Liabilities:		
Deferred Income Taxes	3,379	asset lives
Deferred Gain on Sale of Utility Property - Minnesota Portion	123	264 months
Deferred Marked-to-Market Gains	97	12 months
South Dakota - Nonasset-Based Margin Sharing Excess	54	12 months
Minnesota Transmission Rider Accrued Refund	28	see notes
Total Regulatory Liabilities	\$ 3,681	
Net Regulatory Asset Position	\$ 135,525	

The regulatory asset related to the unrecognized transition obligation, 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 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, 2012 are related to forward purchases of energy scheduled for delivery through December 2018.

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

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

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

North Dakota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying renewable resource costs incurred to serve North Dakota customers that have not been billed to North Dakota customers as of December 31, 2012.

MISO Schedule 26 Transmission Cost Recovery Rider True-up relates to the Minnesota jurisdictional portion of MISO Schedule 26 for regional transmission cost recovery that was included in the calculation of the Minnesota Transmission Rider and subsequently adjusted to reflect actual billing amounts in the schedule. The December 31, 2012 balance will be amortized on a straight-line basis over a period of 12 months beginning in January 2014.

Minnesota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying 2008 through December 31, 2012 renewable resource costs incurred to serve Minnesota customers that have not been billed to

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Minnesota customers as of December 31, 2012.

General Rate Case Recoverable Expenses relate to expenses incurred during rate case proceedings that are eligible for recovery.

North Dakota Transmission Rider Accrued Revenues relate to revenues earned on qualifying transmission system facilities and net operating costs incurred to serve North Dakota customers that have not been billed to North Dakota customers as of December 31, 2012.

The South Dakota Transmission Rider Accrued Revenues relate to revenues billed for qualifying transmission system facilities and operating costs incurred to serve South Dakota customers net of transmission revenues that are refundable to South Dakota customers as of December 31, 2012.

The Minnesota Transmission Rider Accrued Refund relates to revenues billed for qualifying transmission system facilities and operating costs incurred to serve Minnesota customers net of transmission revenues that are refundable to Minnesota customers as of December 31, 2012.

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

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 optimize the use of its generating and transmission facilities and leverage its knowledge of wholesale energy markets in the region to maximize financial returns for the benefit of both its customers and Otter Tail Corporation shareholders. 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. OTP also enters into certain contracts for trading purposes with the intent to profit from fluctuations in market prices through the timing of purchases and sales.

As of December 31, 2012 OTP had recognized, on a pretax basis, \$49,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity. The market prices used to value OTP's forward contracts for the purchases and sales of electricity and electricity generating capacity 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 2 and level 3 of the fair value hierarchy set forth in ASC 820, *Fair Value Measurement*.

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

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MISO, ERCOT and California Independent Transmission System Operator markets, broken down as follows for the years ended December 31:

<i>(in thousands)</i>	2012	2011
Wholesale Sales - Company-Owned Generation	\$ 12,951	\$ 14,518
Revenue from Settled Contracts at Market Prices	160,987	168,313
Market Cost of Settled Contracts	(159,500)	(166,920)
Net Margins on Settled Contracts at Market	1,487	1,393
Marked-to-Market Gains on Settled Contracts	7,864	10,208
Marked-to-Market Losses on Settled Contracts	(7,974)	(10,176)
Net Marked-to-Market (Losses) Gains on Settled Contracts	(110)	32
Unrealized Marked-to-Market Gains on Open Contracts	284	3,707
Unrealized Marked-to-Market Losses on Open Contracts	(235)	(2,813)
Net Unrealized Marked-to-Market Gains on Open Contracts	49	894
Wholesale Electric Revenue	\$ 14,377	\$ 16,837

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, 2012 and December 31, 2011, and the change in OTP's balance sheet position from December 31, 2011 to December 31, 2012 and December 31, 2010 to December 31, 2011:

<i>(in thousands)</i>	December 31, 2012	December 31, 2011
Other Current Asset - Marked-to-Market Gain	\$ 502	\$ 3,803
Regulatory Asset - Deferred Marked-to-Market Loss	17,999	15,957
Total Assets	18,501	19,760
Derivative Liability - Marked-to-Market Loss	(18,234)	(18,770)
Regulatory Liability - Deferred Marked-to-Market Gain	(218)	(96)
Total Liabilities	(18,452)	(18,866)
Net Fair Value of Marked-to-Market Energy Contracts	\$ 49	\$ 894

<i>(in thousands)</i>	Year ended December 31, 2012	Year ended December 31, 2011
Cumulative Fair Value Adjustments Included in Earnings - Beginning of Period	\$ 894	\$ 763
Less: Amounts Realized on Settlement of Contracts Entered into in Prior Periods	(861)	(356)
Changes in Fair Value of Contracts Entered into in Prior Periods	(33)	(86)
Cumulative Fair Value Adjustments in Earnings of Contracts Entered into in Prior Years at End of Period	--	321
Changes in Fair Value of Contracts Entered into in Current Period	49	573
Cumulative Fair Value Adjustments Included in Earnings - End of Period	\$ 49	\$ 894

The \$49,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on December 31, 2012 is expected to be realized on settlement in the first quarter of 2013.

OTP has credit risk associated with the nonperformance or nonpayment by counterparties to its forward energy and capacity purchases and sales agreements. We have established guidelines and limits to manage credit risk associated

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with wholesale power and capacity purchases and sales. Specific limits are determined by a counterparty's financial strength.

The following table provides information on OTP's credit risk exposure on delivered and marked-to-market forward contracts as of December 31, 2012 and December 31, 2011:

<i>(in thousands)</i>	December 31, 2012		December 31, 2011	
	Exposure	Counterparties	Exposure	Counterparties
Net Credit Risk on Forward Energy Contracts	\$ 580	6	\$1,677	10
Net Credit Risk to Single Largest Counterparty	\$ 285		\$ 737	

OTP had a net credit risk exposure to five counterparties with investment grade credit ratings and one counterparty that has not been rated by an external credit rating agency but has been evaluated internally and assigned an internal credit rating equivalent to investment grade. OTP had no exposure at December 31, 2012 or December 31, 2011 to counterparties with credit ratings below investment grade. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch). The credit risk exposures include net amounts due to OTP on receivables/payables from completed transactions billed and unbilled plus marked-to-market gains/losses on forward contracts for the purchase and sale of electricity scheduled for delivery subsequent to the reporting date. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

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, 2012 and December 31, 2011:

<i>(in thousands)</i>	December 31, 2012	December 31, 2011
Current Liability - Marked-to-Market Loss		
Loss Contracts Covered by Deposited Funds or Letters of Credit	\$ 2,176	\$ 3,423
Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade ¹	16,058	15,347
Loss Contracts with No Ratings Triggers or Deposit Requirements	--	--
Total Current Liability - Marked-to-Market Loss	\$ 18,234	\$ 18,770

¹Certain 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	\$ 16,058	\$ 15,347
Offsetting Gains with Counterparties under Master Netting Agreements	(416)	(3,471)
Reporting Date Deposit Requirement if Credit Risk Feature Triggered	\$ 15,642	\$ 11,876

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. On December 31, 2012 Otter Tail Corporation made a \$20,000,000 cash equity contribution to OTP to provide cash for OTP to pay off its line of credit balance of \$7,000,000 on December 30, 2012 and for other purposes.

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6. Retained Earnings and Dividend Restriction

OTP's credit agreements contain restrictions on the payment of cash dividends upon a default or event of default. An event of default would be considered to have occurred if OTP did not meet certain financial covenants. As of December 31, 2012 Otter Tail Corporation and OTP were 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 46.3% and 56.7%. OTP's equity to total capitalization ratio was 52.0% as of December 31, 2012. Total capitalization for OTP cannot exceed \$809 million.

7. Commitments and Contingencies

Construction and Other Purchase Commitments

At December 31, 2012 OTP had commitments under contracts in connection with construction programs aggregating approximately \$79,413,000.

Capacity and Energy Requirements and Coal and Delivery Contracts

OTP has commitments for the purchase of capacity and energy requirements under agreements extending through 2032. 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 2014, 2016 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 continuing operations was \$2,521,000 for 2012 and \$2,745,000 for 2011.

The amounts of OTP's commitments under capacity and energy agreements, coal and coal delivery contracts and operating leases as of December 31, 2012, are as follows:

<i>(in thousands)</i>	Capacity and Energy Requirements	Coal and Freight Purchase Commitments	Operating Leases
2013	\$ 30,964	\$ 42,875	\$ 2,464
2014	15,980	20,384	2,150
2015	13,762	16,886	1,602
2016	16,511	20,803	1,320
2017	15,868	22,047	978
Beyond 2017	77,040	673,961	12,787
Total	\$ 170,125	\$ 796,956	\$ 21,301

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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, 2012 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, 2012 and December 31, 2011:

<i>(in thousands)</i>	Line Limit	In Use on December 31, 2012	Restricted due to Outstanding Letters of Credit	Available on December 31, 2012	Available on December 31, 2011
OTP Credit Agreement	\$ 170,000	--	\$ 3,189	\$ 166,811	\$ 165,950

Under the OTP Credit Agreement referenced below, the maximum amount of debt outstanding in 2012 was \$16,582,000 on August 15, 2012 and the average daily balance of debt outstanding during 2012 was \$5,867,000. The weighted average interest rate paid on debt outstanding under the OTP Credit Agreement during 2012 was 1.7% compared with 1.5% in 2011.

On October 29, 2012 OTP entered into a Second Amended and Restated Credit Agreement (the OTP Credit Agreement) with the Banks named therein. The OTP Credit Agreement amends and restates the \$170 million OTP Credit Agreement dated as of March 3, 2011, which was set to expire on March 3, 2016. The OTP Credit Agreement provides for a \$170 million line of credit that may be increased to \$250 million on the terms and subject to the conditions described in the OTP Credit Agreement. The OTP Credit Agreement is an unsecured revolving credit facility that OTP can draw on 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 the OTP Credit Agreement currently bear interest at LIBOR plus 1.25%, subject to adjustment based on the ratings of OTP's senior unsecured debt. The interest rate being charged under the OTP Credit Agreement prior to the renewal was LIBOR plus 1.5%. Under the OTP Credit Agreement, OTP is required to pay the Banks' commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The OTP Credit Agreement is set to expire on October 29, 2017.

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, as well as a financial covenant under which OTP may not permit the ratio of its "Interest-bearing Debt" to "Total Capitalization" (as defined in the OTP Credit Agreement) to be greater than 0.60 to 1.00. The prior OTP Credit Agreement included similar covenants and events of default, but also included a financial covenant that is not included in the current OTP Credit Agreement, under which OTP could not permit its "Interest and Dividend Coverage Ratio" (as defined in the prior OTP Credit Agreement) to be less than 1.50 to 1.00. 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

On May 11, 2012 Otter Tail Corporation filed a shelf registration statement with the SEC under which it may offer for

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sale, from time to time, either separately or together in any combination, equity and/or debt securities described in the shelf registration statement.

Senior Unsecured Notes 4.63%, due December 1, 2021

On December 1, 2011, OTP issued \$140 million aggregate principal amount of OTP's 4.63% Senior Unsecured Notes due December 1, 2021 (the 2021 Notes) pursuant to a Note Purchase Agreement (the 2011 Note Purchase Agreement), dated as of July 29, 2011, with the purchasers named therein.

Debt Retirements

In the third quarter of 2012, \$25,000 of Grant County, South Dakota Pollution Control Refunding Revenue Bonds 4.65%, due September 1, 2017, and \$35,000 of Mercer County, North Dakota Pollution Control Refunding Revenue Bonds 4.85%, due September 1, 2022, were redeemed for estate settlement purposes.

On December 1, 2011 OTP used a portion of the proceeds from the 2021 Notes to retire \$90 million aggregate principal amount of its 6.63% Senior Notes due December 1, 2011 at maturity and to retire early \$10.4 million aggregate principal amount of its pollution control refunding revenue bonds due December 1, 2012. No penalty was paid for the early retirement.

2007 and 2011 Note Purchase Agreements

The note purchase agreement (the 2007 Note Purchase Agreement) relating to OTP's \$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, as amended and the 2011 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 2007 Note Purchase Agreement and the 2011 Note Purchase Agreement each also states 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, and each contains a number of restrictions on OTP. These include 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 aggregate amounts of maturities on bonds outstanding and other long-term obligations at December 31, 2012 for each of the next five years are:

<i>(in thousands)</i>	2013	2014	2015	2016	2017
Aggregate amounts of Debt Maturities	\$ --	\$ --	\$ --	\$ --	\$ 38,065

Financial Covenants

As of December 31, 2012 OTP was in compliance with the financial statement covenants that existed in its debt agreements.

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

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

- Under the OTP Credit Agreement, OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00.
- Under the 2007 Note Purchase Agreement, 2011 Note Purchase Agreement and the financial guaranty insurance policy with Ambac Assurance Corporation relating to certain pollution control refunding bonds, 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 or insurance agreement. In addition, under the 2007 Note Purchase Agreement and 2011 Note Purchase Agreement, OTP may not permit its Priority Debt to exceed 20% of its Total Capitalization, as provided in the related agreement.

9. Pension Plan and Other Postretirement Benefits

Pension Plan

Otter Tail Corporation's noncontributory funded pension plan (the Plan) covers substantially all OTP nonunion employees hired prior to January 1, 2006, and all OTP union employees. 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. Otter Tail Corporation reserves the right to discontinue the Plan but no change or discontinuance may affect the pensions theretofore vested. OTP's portion of this plan makes up substantially all of the rights and obligations of the Plan. The amounts presented herein are based upon the separate actuarial analysis of OTP and Otter Tail Corporation and its respective employees.

The Plan has a pension fund manager and trustee responsible for managing the Plan's assets and making pension payments to retirees. An independent actuary assists Otter Tail Corporation in performing the necessary actuarial valuations for the Plan.

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

Components of net periodic pension benefit cost:

<i>(in thousands)</i>	2012	2011
Service Cost--Benefit Earned During the Period	\$ 4,952	\$ 4,300
Interest Cost on Projected Benefit Obligation	12,141	12,337
Expected Return on Assets	(14,055)	(13,773)
Amortization of Prior Service Cost	398	423
Amortization of Net Actuarial Loss	4,910	2,549
Net Periodic Pension Cost	\$ 8,346	\$ 5,836

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

	2012	2011
Discount Rate	5.15%	6.00%
Long-Term Rate of Return on Plan Assets	8.00%	8.00%
Rate of Increase in Future Compensation Level	3.38%	3.75%

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

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<i>(in thousands)</i>	2012	2011
Regulatory Assets:		
Unrecognized Prior Service Cost	\$ 1,109	\$ 1,507
Unrecognized Actuarial Loss	98,808	89,820
Total Regulatory Assets	99,917	91,327
Noncurrent Liability	\$ 82,416	\$ 75,480

Funded status as of December 31:

<i>(in thousands)</i>	2012	2011
Accumulated Benefit Obligation	\$(232,500)	\$(205,830)
Projected Benefit Obligation	\$(268,467)	\$(239,699)
Fair Value of Plan Assets	186,051	164,219
Funded Status	\$ (82,416)	\$ (75,480)

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:

<i>(in thousands)</i>	2012	2011
Reconciliation of OTP's Portion of the Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	\$ 164,219	\$ 167,197
Actual Return on Plan Assets	21,964	6,393
Discretionary Company Contributions	10,000	--
Benefit Payments	(10,132)	(9,371)
Fair Value of Plan Assets at December 31	\$ 186,051	\$ 164,219
Estimated Asset Return	13.44%	4.06%
Reconciliation of OTP's Portion of the Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	\$ 239,699	\$ 211,840
Service Cost	4,952	4,300
Interest Cost	12,141	12,337
Benefit Payments	(10,132)	(9,371)
Actuarial Loss	21,807	20,593
Projected Benefit Obligation at December 31	\$ 268,467	\$ 239,699

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

	2012	2011
Discount Rate	4.50%	5.15%
Rate of Increase in Future Compensation Level	3.13%	3.38%

The assumed rate of return on pension fund assets used for the determination of 2013 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. We review our rate of return on plan asset assumptions annually. The assumptions are largely based on the asset category rate-of-return assumptions developed annually with our pension plan investment advisors, as well as input from actuaries who work with the pension plan.

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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:	2012	2011
Net Periodic Pension Cost	January 1, 2012	January 1, 2011
	January 1, 2012 projected to	January 1, 2011 projected to
End of Year Benefit Obligations	December 31, 2012	December 31, 2011
Market Value of Assets	December 31, 2012	December 31, 2011

The estimated amounts of unrecognized net actuarial losses and prior service costs to be amortized from regulatory assets into the net periodic pension cost in 2013 are:

<i>(in thousands)</i>	2013
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	\$ 333
Amortization of Unrecognized Actuarial Loss	6,652
<u>Total Estimated Amortization</u>	<u>\$ 6,985</u>

Cash flows—The Plan had no minimum funding requirement as of December 31, 2012, but OTP made a discretionary plan contribution of \$10,000,000 in January 2013.

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

<i>(in thousands)</i>	2013	2014	2015	2016	2017	Years 2018-2022
	\$10,633	\$10,978	\$11,468	\$11,988	\$12,708	\$76,536

The following objectives guide the investment strategy of the Plan:

- The Plan is managed to operate in perpetuity.
- The Plan will meet the pension benefit obligation payments of OTP.
- The Plan's assets should be invested with the objective of meeting current and future payment requirements while minimizing annual contributions and their volatility.
- The asset strategy reflects the desire to meet current and future benefit payments while considering a prudent level of risk and diversification.

The asset allocation strategy developed by Otter Tail Corporation's Investment Committee is based on the current needs of the Plan, the investment objectives listed above, the investment preferences and risk tolerance of the committee and a desired degree of diversification.

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The asset allocation strategy contains guideline percentages, at market value, of the total Plan invested in various asset classes. The strategic target allocation and the tactical range shown in the table that follows is a guide that will at times not be reflected in actual asset allocations that may be dictated by prevailing market conditions, independent actions of the Investment Committee and/or investment manager, and required cash flows to and from the Plan. The tactical range provides flexibility for the investment manager's portfolio to vary around the target allocation without the need for immediate rebalancing.

Allocation targets and tactical ranges shown below reflect the Investment Policy Statement approved by Otter Tail Corporation's Investment Committee. Each of the asset categories is within its respective tactical range. The Investment Committee monitors actual asset allocations and directs contributions and withdrawals toward maintaining the current targeted allocation percentages listed below.

Asset Allocation	Strategic Target	Tactical Range
Equity Securities	51%	41%-61%
Fixed-Income	44%	34%-54%
Alternatives	5%	0%-12%
Cash	0%	0%-5%

The Plan asset allocations at December 31, 2012 and 2011, by asset category are as follows:

Asset Allocation	2012	2011
Large Capitalization Equity Securities	24.7%	25.7%
International Equity Securities	17.8%	14.4%
Small and Mid-Capitalization Equity Securities	7.1%	6.9%
SEI Dynamic Asset Allocation Fund	4.8%	4.8%
Equity Securities	54.4%	51.8%
Fixed-Income Securities and Cash	41.1%	43.4%
Other - SEI Special Situation Collective Investment Trust	4.5%	4.8%
	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 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 share of pension fund assets measured at fair

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value as of December 31, 2012 and 2011:

2012 (in thousands)	Level 1	Level 2	Level 3
Large Capitalization Equity Securities	\$ 45,859		
International Equity Securities	33,202		
Small and Mid-Capitalization Equity Securities	13,259		
SEI Dynamic Asset Allocation Fund	8,938		
Fixed Income Securities	76,439		
Cash Management - Money Market Fund	11		
SEI Special Situation Collective Investment Trust			\$ 8,343
Total Assets	\$ 177,708	\$ --	\$ 8,343
2011 (in thousands)			
Large Capitalization Equity Securities	\$ 42,207		
International Equity Securities	23,663		
Small and Mid-Capitalization Equity Securities	11,266		
SEI Dynamic Asset Allocation Fund	7,922		
Fixed Income Securities	70,354		
Cash Management - Working Capital Account		\$ 887	
SEI Special Situation Collective Investment Trust			\$ 7,920
Total Assets	\$ 155,412	\$ 887	\$ 7,920

The level 3 investments in the SEI Special Situation Collective Investment Trust consist 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. The fair value of the fund is calculated independently by the fund's administrator and is reviewed by the management team. There were no significant transfers between Levels 1, 2 or 3 during the year ended December 31, 2012. The initial investment in the SEI Special Situation Collective Investment Trust was made in January 2011.

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>	2012	2011
Service Cost--Benefit Earned During the Period	\$ 45	\$ 48
Interest Cost on Projected Benefit Obligation	857	959
Amortization of Prior Service Cost	155	43
Amortization of Net Actuarial Loss	258	144
Net Periodic Pension Cost	\$ 1,315	\$ 1,194

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

	2012	2011
Discount Rate	5.15%	6.00%
Rate of Increase in Future Compensation Level	4.59%	4.65%

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

<i>(in thousands)</i>	2012	2011
Regulatory Assets:		
Unrecognized Prior Service Cost	\$ 135	\$ 215
Unrecognized Actuarial Loss	2,788	2,427
Total Regulatory Assets	2,923	2,642
Projected Benefit Obligation Liability - Net Amount Recognized	(17,600)	(17,244)
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	75	120
Unrecognized Actuarial Loss	1,552	1,351
Total Accumulated Other Comprehensive Loss	1,627	1,471
Deferred Income Taxes	1,085	980

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, 2012:

<i>(in thousands)</i>	2012	2011
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	1,259	1,072
Benefit Payments	(1,259)	(1,072)
Fair Value of Plan Assets at December 31	\$ --	\$ --
Reconciliation of OTP's Portion of the Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	\$ 17,244	\$ 16,057
Service Cost	45	48
Interest Cost	857	959
Benefit Payments	(1,259)	(1,072)
Liability Transfer from OTP to Otter Tail Corporation	(242)	--
Actuarial Loss	955	1,252
Projected Benefit Obligation at December 31	\$ 17,599	\$ 17,244

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

	2012	2011
Discount Rate	4.50%	5.15%
Rate of Increase in Future Compensation Level	3.25%	4.59%

The estimated amounts of unrecognized net actuarial losses and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic pension cost for the ESSRP in 2013 are:

<i>(in thousands)</i>	2013
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	\$ 22
Amortization of Unrecognized Actuarial Loss	208
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	21

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Amortization of Unrecognized Actuarial Loss	193
Total Estimated Amortization	\$ 444

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>	2013	2014	2015	2016	2017	Years 2018-2022
	\$1,194	\$1,219	\$1,209	\$1,195	\$1,165	\$6,118

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. On adoption of Statement of Financial Accounting Standards No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*, in January 1993, OTP elected to recognize its transition obligation related to postretirement benefits earned of approximately \$14,548,000 over a period of 20 years. There are no plan assets.

Components of net periodic postretirement benefit cost:

<i>(in thousands)</i>	2012	2011
Service Cost--Benefit Earned During the Period	\$ 1,752	\$ 1,484
Interest Cost on Projected Benefit Obligation	3,410	3,329
Amortization of Transition Obligation	723	729
Amortization of Prior Service Cost	205	205
Amortization of Net Actuarial Loss	1,477	814
Expense Decrease Due to Medicare Part D Subsidy	(1,986)	(2,063)
Net Periodic Postretirement Benefit Cost	\$ 5,581	\$ 4,498

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

	2012	2011
Discount Rate	5.05%	5.75%

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

<i>(in thousands)</i>	2012	2011
Regulatory Asset:		
Unrecognized Transition Obligation	\$ --	\$ 723
Unrecognized Prior Service Cost	745	950
Unrecognized Net Actuarial Loss	14,364	6,736
Net Regulatory Asset	\$ 15,109	\$ 8,409
Projected Benefit Obligation Liability - Net Amount Recognized	\$ (57,352)	\$ (47,009)

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, 2012:

<i>(in thousands)</i>	2012	2011
Reconciliation of OTP's Portion of the Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	\$ --	\$ --

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NOTES TO FINANCIAL STATEMENTS (Continued)			

Actual Return on Plan Assets	--	--
Company Contributions	1,938	2,066
Benefit Payments (Net of Medicare Part D Subsidy)	(4,259)	(4,119)
Participant Premium Payments	2,321	2,053
Fair Value of Plan Assets at December 31	\$ --	\$ --
Reconciliation of OTP's Portion of the Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	\$ 47,009	\$ 41,355
Service Cost (Net of Medicare Part D Subsidy)	1,504	1,242
Interest Cost (Net of Medicare Part D Subsidy)	2,508	2,322
Benefit Payments (Net of Medicare Part D Subsidy)	(4,259)	(4,119)
Participant Premium Payments	2,321	2,053
Actuarial Loss	8,269	4,156
Projected Benefit Obligation at December 31	\$ 57,352	\$ 47,009

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

	2012	2011
Discount Rate	4.25%	5.05%

Assumed healthcare cost-trend rates as of December 31:

	2012	2011
Healthcare Cost-Trend Rate Assumed for Next Year Pre-65	6.62%	6.78%
Healthcare Cost-Trend Rate Assumed for Next Year Post-65	7.01%	7.21%
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 2012 would have the following effects:

<i>(in thousands)</i>	1 Point Increase	1 Point Decrease
Effect on the Postretirement Benefit Obligation	\$ 7,524	\$ (6,235)
Effect on Total of Service and Interest Cost	\$ 682	\$ (545)
Effect on Expense	\$ 1,295	\$ (1,060)

Measurement Dates:	2012	2011
Net Periodic Postretirement Benefit Cost	January 1, 2012	January 1, 2011
	January 1, 2012 projected to December 31, 2012	January 1, 2011 projected to December 31, 2011
End of Year Benefit Obligations		

The estimated net amounts of unrecognized transition obligation and prior service costs to be amortized from regulatory assets into the net periodic postretirement benefit cost in 2013 are:

<i>(in thousands)</i>	2013
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	\$ 205
Amortization of Unrecognized Actuarial Loss	991

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NOTES TO FINANCIAL STATEMENTS (Continued)			

Total Estimated Amortization	\$ 1,196
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Cash flows—OTP expects to contribute \$2.9 million net of expected employee contributions for the payment of retiree medical benefits and Medicare Part D subsidy receipts in 2013. OTP expects to receive a Medicare Part D subsidy from the Federal government of approximately \$498,000 in 2012. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

<i>(in thousands)</i>	2013	2014	2015	2016	2017	Years 2018-2022
	\$2,879	\$3,041	\$3,143	\$3,278	\$3,488	\$19,837

401K Plan

OTP has a 401K plan for the benefit of all its employees. Contributions made to this plan by OTP totaled \$1,320,000 for 2012 and \$1,511,000 for 2011.

Employee Stock Ownership Plan

OTP has a stock ownership plan for the benefit of all its employees. Contributions made by OTP were \$735,000 for 2012 and \$760,000 for 2011.

10. Fair Value of Financial Instruments

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

Cash and Short-Term Investments—The carrying amount approximates fair value because of the short-term maturity of those instruments.

Long-Term Debt—The fair value of OTP's long-term debt is estimated based on the current rates available to OTP for the issuance of debt. OTP's long-term debt subject to variable interest rates approximates fair value.

<i>(in thousands)</i>	December 31, 2012		December 31, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Short-Term Investments	\$ 12,333	\$ 12,333	\$ 14,505	\$ 14,505
Long-Term Debt	(335,635)	(389,023)	(335,695)	(376,881)

11. Property, Plant and Equipment

<i>(in thousands)</i>	December 31, 2012	December 31, 2011	Service Life Range (years)	
			Low	High
Electric Plant				
Production	\$ 672,120	\$ 669,805	34	62
Transmission	261,447	229,320	40	55
Distribution	405,461	390,383	15	55
General	84,275	83,026	5	70
Electric Plant in Service	1,423,303	1,372,534		
Construction Work in Progress	75,758	49,123		
Other Property - Land	516	430		
Total Plant	1,499,577	1,422,087		
Less Accumulated Depreciation and Amortization	592,428	564,937		

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NOTES TO FINANCIAL STATEMENTS (Continued)			

Net Plant	\$ 907,149	\$ 857,150
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12. Income Taxes

The total income tax expense differs from the amount computed by applying the federal income tax rate (35% in 2012 and 2011) to net income before total income tax expense for the following reasons:

<i>(in thousands)</i>	2012	2011
Tax Computed at Federal Statutory Rate	\$ 15,902	\$ 15,510
Increases (Decreases) in Tax from:		
State Income Taxes Net of Federal Income Tax Benefit	1,733	1,953
Federal Production Tax Credit	(6,695)	(7,281)
North Dakota Wind Tax Credit Amortization - Net of Federal Taxes	(891)	(996)
Investment Tax Credit Amortization	(720)	(855)
Dividend Received/Paid Deduction	(656)	(677)
Impact of Change in Treatment of Medicare Part D Payments	(564)	(599)
Allowance for Funds Used During Construction - Equity	(409)	(301)
Tax Depreciation - Treasury Grant for Wind Farms	(304)	(507)
Differences Reversing in Excess of Federal Rates	(143)	680
Permanent and Other Differences	(291)	(1,161)
Total Income Tax Expense	\$ 6,962	\$ 5,766
Overall Effective Federal and State Income Tax Rate	15.3%	13.0%
Income Tax Expense Includes the Following:		
Current Federal Income Taxes	\$ 5,646	\$ 6,967
Current State Income Taxes	910	122
Deferred Federal Income Taxes	7,436	5,463
Deferred State Income Taxes	1,276	2,346
Federal Production Tax Credit	(6,695)	(7,281)
North Dakota Wind Tax Credit Amortization - Net of Federal Taxes	(891)	(996)
Investment Tax Credit Amortization	(720)	(855)
Total	\$ 6,962	\$ 5,766

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

<i>(in thousands)</i>	2012	2011
Deferred Tax Assets		
North Dakota Wind Tax Credits	\$ 44,172	\$ 44,370
Benefit Liabilities	24,814	22,594
Federal Production Tax Credits	21,625	15,238
Differences Related to Property	9,021	9,592
Net Operating Loss Carryforward	7,446	7,727
Investment Tax Credits	2,554	3,380
Vacation Accrual	1,379	1,403
Other	4,965	5,129
Total Deferred Tax Assets	\$ 115,976	\$ 109,433
Deferred Tax Liabilities		
Differences Related to Property	\$(258,946)	\$(240,470)
North Dakota Wind Tax Credits	(11,923)	(11,850)

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NOTES TO FINANCIAL STATEMENTS (Continued)			

Excess Tax over Book Pension	(6,924)	(6,282)
Impact of State Net Operating Losses on Federal Taxes	(2,612)	(2,710)
Regulatory Asset	(4,859)	(5,542)
Renewable Resource Rider Accrued Revenue	(934)	(1,913)
Other	(2,027)	(3,010)
Total Deferred Tax Liabilities	\$(288,225)	\$(271,777)
Deferred Income Taxes	\$(172,249)	\$(162,344)

Schedule of expiration of tax net operating losses and tax credits available as of December 31, 2012:

<i>(in thousands)</i>	Amount	Year of Expiration				
		2013	2014	2015	2016	2024-33
Federal Tax Credits	\$ 27,156	\$ --	\$ --	\$ --	\$ --	\$ 27,156
State Net Operating Losses	7,716	--	--	--	--	7,716
State Tax Credits	43,222	2,461	1,950	1,950	1,950	34,911

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 \$9.2 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>	2012	2011
Balance at January 1	\$ 11,238	\$ --
Increases Related to Tax Positions	--	11,238
Uncertain Positions Resolved During Year	(6,802)	--
Balance at December 31	\$ 4,436	\$ 11,238

There was no amount accrued for interest on tax uncertainties as of December 31, 2012.

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, 2012, with limited exceptions, Otter Tail Corporation is no longer subject to examinations by taxing authorities for tax years prior to 2009.

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 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 2012.

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, 2012 and 2011 are presented in the following table:

<i>(in thousands)</i>	2012	2011
Asset Retirement Obligations		
Beginning Balance	\$ 4,808	\$ 4,402

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NOTES TO FINANCIAL STATEMENTS (Continued)			

New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	(20)	22
Accrued Accretion	419	384
Settlements	--	--
Ending Balance	\$ 5,207	\$ 4,808
<u>Asset Retirement Costs Capitalized</u>		
Beginning Balance	\$ 1,497	\$ 1,497
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	(20)	--
Settlements	--	--
Ending Balance	\$ 1,477	\$ 1,497
<u>Accumulated Depreciation - Asset Retirement Costs Capitalized</u>		
Beginning Balance	\$ 351	\$ 290
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	4
Depreciation Expense	56	57
Settlements	--	--
Ending Balance	\$ 407	\$ 351
<u>Settlements</u>		
Original Capitalized Asset Retirement Cost - Retired	\$ --	\$ --
Accumulated Depreciation	--	--
Asset Retirement Obligation	\$ --	\$ --
Settlement Cost	--	--
Gain on Settlement - Deferred Under Regulatory Accounting	\$ --	\$ --

14. Subsequent Events

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) due June 1, 2014, which was fully drawn on March 1, 2013. Borrowings under the Loan Agreement will bear interest at LIBOR plus 0.875%. The Loan Agreement permits OTP to use the loan proceeds to fund working capital, capital expenditures and other purposes. On March 1, 2013 OTP utilized approximately \$25.1 million of the proceeds to fund the redemption of 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. All such bonds had been called for redemption in full on March 1, 2013. Also on March 1, 2013, OTP utilized approximately \$15.8 million of the loan proceeds to repay in full its four intercompany notes held by its parent company, Otter Tail Corporation.

The Loan 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 Loan Agreement also contains affirmative covenants and events of default, as well as a financial covenant under which OTP may not permit the ratio of its Interest bearing Debt to Total Capitalization (as defined in the Loan Agreement) to be greater than 0.60 to 1.00. The Loan 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 or Otter Tail Corporation's credit ratings. OTP's obligations under the Loan Agreement are not guaranteed by any other party. OTP may prepay borrowings without premium or penalty upon notice to JPMorgan as provided in the Loan Agreement.

15. Quantitative and Qualitative Disclosures About Market Risk

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NOTES TO FINANCIAL STATEMENTS (Continued)			

At December 31, 2012 OTP had no exposure to market risk associated with interest rates because OTP had no debt outstanding subject to variable interest rates.

All of OTP's long-term debt 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 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 market, price and credit risk associated with forward contracts for the purchase and sale of electricity. As of December 31, 2012 OTP had recognized, on a pretax basis, \$49,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity and electricity generating capacity. Due to the nature of electricity and the physical aspects of the electricity transmission system, unanticipated events affecting the transmission grid can cause transmission constraints that result in unanticipated gains or losses in the process of settling transactions.

The market prices used to value OTP's forward contracts for the purchases and sales of electricity and electricity generating capacity 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 the 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 forward energy purchase contracts that are marked to market as of December 31, 2012, are 100% offset by forward energy sales contracts in terms of volumes, delivery periods and points of delivery. The differential in forward prices at the different delivery locations currently results in a net mark-to-market unrealized gain on OTP's forward energy contracts of \$49,000.

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 purchases and sales. Volumetric limits and loss limits are used to adequately manage the risks associated with our energy trading activities. Additionally, OTP has a Value at Risk (VaR) limit to further manage market price risk. There was no price risk on open positions as of December 31, 2012 because the open purchases were offset by open sales at the same point of delivery.

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 the Company's balance sheets as of December 31, 2012 and December 31, 2011, and the change in the Company's balance sheet position from December 31, 2011 to December 31, 2012 and December 31, 2010 to December 31, 2011:

<i>(in thousands)</i>	December 31, 2012	December 31, 2011
Current Asset - Marked-to-Market Gain	\$ 502	\$ 3,803
Regulatory Asset - Deferred Marked-to-Market Loss	17,999	15,957
Total Assets	18,501	19,760
Current Liability - Marked-to-Market Loss	(18,234)	(18,770)
Regulatory Liability - Deferred Marked-to-Market Gain	(218)	(96)
Total Liabilities	(18,452)	(18,866)
Net Fair Value of Marked-to-Market Energy Contracts	\$ 49	\$ 894

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NOTES TO FINANCIAL STATEMENTS (Continued)			

<i>(in thousands)</i>	Year ended December 31, 2012	Year ended December 31, 2011
Cumulative Fair Value Adjustments Included in Earnings - Beginning of Period	\$ 894	\$ 763
Less: Amounts Realized on Settlement of Contracts Entered into in Prior Periods	(861)	(356)
Changes in Fair Value of Contracts Entered into in Prior Periods	(33)	(86)
Cumulative Fair Value Adjustments in Earnings of Contracts Entered into in Prior Years at End of Period	--	321
Changes in Fair Value of Contracts Entered into in Current Period	49	573
Cumulative Fair Value Adjustments Included in Earnings - End of Period	\$ 49	\$ 894

The \$49,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on December 31, 2012 is expected to be realized on settlement in the first quarter of 2013.

The following realized and unrealized net (losses) and gains on forward energy contracts are included in electric operating revenues on OTP's statements of income:

<i>(in thousands)</i>	Year Ended December 31,		
	2012	2011	2010
Net (Losses) Gains on Forward Electric Energy Contracts	\$ (61)	\$ 926	\$2,135

OTP has credit risk associated with the nonperformance or nonpayment by counterparties to its forward energy and capacity purchases and sales agreements. We have 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. OTP's credit risk with its largest counterparty on delivered and marked-to-market forward contracts as of December 31, 2012 was \$285,000. As of December 31, 2012 OTP had a net credit risk exposure of \$580,000 from five counterparties with investment grade credit ratings and one counterparty that has not been rated by an external credit rating agency but has been evaluated internally and assigned an internal credit rating equivalent to investment grade. OTP had no exposure at December 31, 2012 to counterparties with credit ratings below investment grade. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch). The \$580,000 credit risk exposure included net amounts due to OTP on receivables/payables from completed transactions billed and unbilled plus marked-to-market gains/losses on forward contracts for the purchase and sale of electricity scheduled for delivery after December 31, 2012. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

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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)	1,382,982,970	1,382,982,970
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	38,642,984	38,642,984
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	1,421,625,954	1,421,625,954
9	Leased to Others		
10	Held for Future Use	29,656	29,656
11	Construction Work in Progress	75,758,114	75,758,114
12	Acquisition Adjustments	1,647,129	1,647,129
13	Total Utility Plant (8 thru 12)	1,499,060,853	1,499,060,853
14	Accum Prov for Depr, Amort, & Depl	592,427,672	592,427,672
15	Net Utility Plant (13 less 14)	906,633,181	906,633,181
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	589,037,503	589,037,503
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	1,885,946	1,885,946
22	Total In Service (18 thru 21)	590,923,449	590,923,449
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	1,504,223	1,504,223
33	Total Accum Prov (equals 14) (22,26,30,31,32)	592,427,672	592,427,672

Name of Respondent
Otter Tail Power Company

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(2) A Resubmission

Date of Report
(Mo, Da, Yr)
12/31/2012

Year/Period of Report
End of 2012/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
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Name of Respondent	This Report is:	Date of Report	Year/Period of Report
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FOOTNOTE DATA			

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

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

	Gross Electric Plant in Service
December 31, 2011	1,370,857,338
January 31, 2012	1,371,320,378
February 29, 2012	1,375,945,578
March 31, 2012	1,376,974,197
April 30, 2012	1,380,823,487
May 31, 2012	1,378,333,708
June 30, 2012	1,379,003,285
July 31, 2012	1,381,804,412
August 31, 2012	1,400,403,104
September 30, 2012	1,408,051,874
October 31, 2012	1,410,299,196
November 30, 2012	1,414,039,202
December 31, 2012	1,421,625,954
13-month average for rate-making	1,389,960,132

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 in Rate Base	CWIP not in Rates
December 31, 2011	49,123,094	25,519,260	23,603,834
January 31, 2012	52,141,886	26,550,962	25,590,924
February 29, 2012	53,019,608	24,183,612	28,835,996
March 31, 2012	59,015,030	27,599,808	31,415,222
April 30, 2012	61,705,071	30,599,350	31,105,721
May 31, 2012	70,449,977	36,695,686	33,754,291
June 30, 2012	77,453,086	41,356,466	36,096,620
July 31, 2012	82,695,113	43,238,520	39,456,593
August 31, 2012	69,873,802	44,217,335	25,656,467
September 30, 2012	68,758,418	45,318,067	23,440,351
October 31, 2012	74,927,784	49,258,446	25,669,338
November 30, 2012	75,929,146	46,917,774	29,011,372
December 31, 2012	75,758,114	44,522,592	31,235,522
13-month average for rate-making		37,382,914	

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year
			Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials		
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)		
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)		
10	SUBTOTAL (Total 8 & 9)		
11	Spent Nuclear Fuel (120.4)		
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)		
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)		
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

Name of Respondent

Otter Tail Power Company

This Report Is:

(1) An Original

(2) A Resubmission

Date of Report

(Mo, Da, Yr)

12/31/2012

Year/Period of Report

End of 2012/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance End of Year (f)	Line No.
Amortization (d)	Other Reductions (Explain in a footnote) (e)		
			1
			2
			3
			4
			5
			6
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			22

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2012	Year/Period of Report 2012/Q4
FOOTNOTE DATA			

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

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

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	1,301,974	
4	(303) Miscellaneous Intangible Plant	3,378,227	813,919
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	4,680,201	813,919
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,710,632	
9	(311) Structures and Improvements	60,445,814	1,473,608
10	(312) Boiler Plant Equipment	204,979,431	1,992,843
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	58,463,516	3,368,504
13	(315) Accessory Electric Equipment	23,116,645	192,555
14	(316) Misc. Power Plant Equipment	5,550,531	6,429
15	(317) Asset Retirement Costs for Steam Production	314,745	-20,236
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	354,581,314	7,013,703
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	335,800	16,203
29	(332) Reservoirs, Dams, and Waterways	2,376,630	838,323
30	(333) Water Wheels, Turbines, and Generators	1,067,507	-7,884
31	(334) Accessory Electric Equipment	597,919	7,364
32	(335) Misc. Power PLant Equipment	148,674	308,425
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)	4,834,153	1,162,431
36	D. Other Production Plant		
37	(340) Land and Land Rights	126,762	
38	(341) Structures and Improvements	12,672,501	49,031
39	(342) Fuel Holders, Products, and Accessories	1,581,377	200,671
40	(343) Prime Movers	31,557,859	100,789
41	(344) Generators	240,198,548	571,926
42	(345) Accessory Electric Equipment	19,744,182	125,469
43	(346) Misc. Power Plant Equipment	435,506	27,969
44	(347) Asset Retirement Costs for Other Production	1,182,022	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	307,498,757	1,075,855
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	666,914,224	9,251,989

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	422,825	519,712
49	(352) Structures and Improvements		
50	(353) Station Equipment	66,485,998	8,557,583
51	(354) Towers and Fixtures	4,692,263	
52	(355) Poles and Fixtures	84,757,684	18,655,102
53	(356) Overhead Conductors and Devices	72,816,758	5,052,923
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)	229,252,989	32,785,320
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	1,055,586	6,125
61	(361) Structures and Improvements		
62	(362) Station Equipment	64,204,882	3,963,672
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	62,643,866	2,070,202
65	(365) Overhead Conductors and Devices	44,956,508	1,160,712
66	(366) Underground Conduit		
67	(367) Underground Conductors and Devices	61,084,294	2,160,128
68	(368) Line Transformers	71,186,693	4,917,618
69	(369) Services	45,397,419	1,756,073
70	(370) Meters	31,200,412	1,211,521
71	(371) Installations on Customer Premises	4,015,485	306,110
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	4,616,893	236,766
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	390,362,038	17,788,927
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	1,526,512	
87	(390) Structures and Improvements	29,288,680	285,544
88	(391) Office Furniture and Equipment	8,556,927	1,017,401
89	(392) Transportation Equipment	28,739,526	1,831,782
90	(393) Stores Equipment		
91	(394) Tools, Shop and Garage Equipment	3,756,326	262,229
92	(395) Laboratory Equipment	18,180	
93	(396) Power Operated Equipment	591,249	-5,133
94	(397) Communication Equipment	7,170,486	538,730
95	(398) Miscellaneous Equipment		
96	SUBTOTAL (Enter Total of lines 86 thru 95)	79,647,886	3,930,553
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)	79,647,886	3,930,553
100	TOTAL (Accounts 101 and 106)	1,370,857,338	64,570,708
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)	1,370,857,338	64,570,708

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
		1,516,132	2,458,669	48
				49
152,323		4,944	74,896,202	50
			4,692,263	51
237,828		-1,537,489	101,637,469	52
149,120		-102,660	77,617,901	53
				54
			77,461	55
				56
				57
539,271		-119,073	261,379,965	58
				59
1,000			1,060,711	60
				61
624,999		-159,851	67,383,704	62
				63
126,250		55,425	64,643,243	64
268,776		68,592	45,917,036	65
				66
155,209			63,089,213	67
428,907		21,375	75,696,779	68
46,590			47,106,902	69
745,592			31,666,341	70
191,195			4,130,400	71
				72
108,713			4,744,946	73
				74
2,697,231		-14,459	405,439,275	75
				76
				77
				78
				79
				80
				81
				82
				83
				84
				85
4,616			1,521,896	86
85,219		-5,490	29,483,515	87
1,795,013		5,490	7,784,805	88
1,307,291			29,264,017	89
				90
172,559			3,845,996	91
18,180				92
			586,116	93
62,040		-68,789	7,578,387	94
				95
3,444,918		-68,789	80,064,732	96
				97
				98
3,444,918		-68,789	80,064,732	99
13,802,092			1,421,625,954	100
				101
				102
				103
13,802,092			1,421,625,954	104

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Power Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2012	2012/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, 2011	4,680,201
January 31, 2012	4,680,202
February 29, 2012	4,922,879
March 31, 2012	4,990,275
April 30, 2012	4,997,463
May 31, 2012	4,997,463
June 30, 2012	4,868,026
July 31, 2012	4,870,214
August 31, 2012	5,093,746
September 30, 2012	5,093,746
October 31, 2012	4,954,496
November 30, 2012	4,954,496
December 31, 2012	4,210,738
13-month average for rate-making	4,870,303

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, 2011	666,914,224
January 31, 2012	667,368,946
February 29, 2012	667,232,663
March 31, 2012	667,350,044
April 30, 2012	667,653,883
May 31, 2012	664,042,480
June 30, 2012	663,840,584
July 31, 2012	664,931,110
August 31, 2012	665,538,423
September 30, 2012	665,802,412
October 31, 2012	666,235,068
November 30, 2012	669,869,679
December 31, 2012	670,531,244
13-month average for rate-making	666,716,212

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, 2011	229,252,989
January 31, 2012	229,141,238
February 29, 2012	232,392,700
March 31, 2012	232,683,898

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) 12/31/2012	2012/Q4
FOOTNOTE DATA			

April 30, 2012	234,817,655
May 31, 2012	235,132,983
June 30, 2012	235,344,166
July 31, 2012	235,568,119
August 31, 2012	252,724,533
September 30, 2012	258,237,590
October 31, 2012	258,746,267
November 30, 2012	257,795,859
December 31, 2012	261,379,965
13-month average for rate-making	242,555,228

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, 2011	390,362,038
January 31, 2012	390,803,561
February 29, 2012	391,625,279
March 31, 2012	392,233,882
April 30, 2012	393,407,290
May 31, 2012	394,282,398
June 30, 2012	395,202,669
July 31, 2012	396,261,168
August 31, 2012	397,161,249
September 30, 2012	398,994,350
October 31, 2012	400,250,734
November 30, 2012	401,453,562
December 31, 2012	405,439,275
13-month average for rate-making	395,959,804

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, 2011	79,647,886
January 31, 2012	79,326,431
February 29, 2012	79,772,057
March 31, 2012	79,716,098
April 30, 2012	79,947,196
May 31, 2012	79,878,383
June 30, 2012	79,747,840
July 31, 2012	80,173,801
August 31, 2012	79,885,153
September 30, 2012	79,923,776
October 31, 2012	80,112,630
November 30, 2012	79,965,607
December 31, 2012	80,064,732

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) 12/31/2012	2012/Q4
FOOTNOTE DATA			

13-month average for rate-making 79,858,584

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1	Not applicable				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
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40					
41					
42					
43					
44					
45					
46					
47	TOTAL				

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Various			29,656
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Various			
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			29,656

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2012	Year/Period of Report 2012/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

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

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

	Transmission	Distribution	Total
December 31, 2011	9,037	20,619	29,656
January 31, 2012	9,037	20,619	29,656
February 28, 2012	9,037	20,619	29,656
March 31, 2012	9,037	20,619	29,656
April 30, 2012	9,037	20,619	29,656
May 31, 2012	9,037	20,619	29,656
June 30, 2012	9,037	20,619	29,656
July 31, 2012	9,037	20,619	29,656
August 31, 2012	9,037	20,619	29,656
September 30, 2012	9,037	20,619	29,656
October 31, 2012	9,037	20,619	29,656
November 30, 2012	9,037	20,619	29,656
December 31, 2012	9,037	20,619	29,656
13-month average for rate-making			29,656

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or \$1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Bottineau, ND - build new substation	179,006
2	Bottineau, ND - 12.5 kv conversion project - Phase II	161,051
3	Brookings - SE Twin Cities - construct transmission line	2,275,748
4	Fergus Falls, MN - peaking plant development	870,464
5	Fergus Falls, MN - Hoot Lake Plant - replace switchgear	404,773
6	Fergus Falls, MN - GIS software development	319,180
7	Big Stone City, SD - AQCS environmental project	21,836,742
8	Fergus Falls, MN - Hoot Lake plant study	308,363
9	Big Stone transmission - regulatory recovery	5,434,272
10	Big Stone City, SD - transmission line project	2,174,641
11	Fargo, ND - St. Cloud, MN - transmission line project - Phase II	14,355,195
12	Big Stone City, SD - Big Stone Plant - brine waste water recycle addition	314,449
13	Bemidji, MN - transmission systems improvements	1,440,886
14	Big Stone, SD - Ellendale, ND - transmission line project	841,287
15	Maple River, ND - Wahpeton, ND - 230 kv line upgrade	153,025
16	Oakes, ND - area transmission improvements	179,568
17	Fargo, ND - St. Cloud, MN - transmission line project - Phase III	4,919,896
18	Fergus Falls, MN - install UG services	109,994
19	Fergus Falls, MN - replace unit #227	495,040
20	Casselton, ND - Buffalo, ND - 115kv line project	2,529,976
21	Fergus Falls, MN - construct backup control center	1,159,343
22	Sheyenne, ND - Audubon, MN - 230 kv line improvements	162,514
23	Ramsey, ND - install transformer	432,865
24	System Wide - fiber/microwave communication installations	105,219
25	System Wide - radio system replacement	242,285
26	System Wide - communication tower upgrades	137,283
27	Fergus Falls, MN - customer information system project	385,232
28	System Wide - PC life cycle replacements	165,084
29	Fergus Falls, MN - network equipment	233,610
30	Fergus Falls, MN - capital budget software	174,289
31	Lyon County, SD - Cedar Mountain, SD - transmission line project	491,404
32	Helena-Cedar Mountain, SD - transmission line project	4,460,764
33	System Wide - transmission line analysis and GIS information collection	353,602
34	Buelah, ND - Coyote Station - generator stator and rotor rewind	262,500
35	Binford, ND - buiild new substation	202,216
36	Bottineau, ND - 12.5kv conversion project - Phase II	260,282
37	Parkers Prairie, MN - uprate town west feeder	240,670
38	Bemidji, MN - survey for new substation	100,688
39	Oslo, MN - relocate 115kv line	167,396
40	Belcourt, ND - construct 12.5kv line	533,015
41	Miscellaneous projects under \$100,000	6,184,297
42		
43	TOTAL	75,758,114

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	561,033,858	561,033,858		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	39,722,146	39,722,146		
4	(403.1) Depreciation Expense for Asset Retirement Costs	56,309	56,309		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,517,423	1,517,423		
7	Other Clearing Accounts	92,646	92,646		
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	41,388,524	41,388,524		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	12,444,737	12,444,737		
13	Cost of Removal	3,057,892	3,057,892		
14	Salvage (Credit)	1,457,876	1,457,876		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	14,044,753	14,044,753		
16	Other Debit or Cr. Items (Describe, details in footnote):	659,874	659,874		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	589,037,503	589,037,503		

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

20	Steam Production	225,842,471	225,842,471		
21	Nuclear Production				
22	Hydraulic Production-Conventional	2,180,253	2,180,253		
23	Hydraulic Production-Pumped Storage				
24	Other Production	60,148,408	60,148,408		
25	Transmission	94,847,883	94,847,883		
26	Distribution	172,765,161	172,765,161		
27	Regional Transmission and Market Operation				
28	General	33,253,327	33,253,327		
29	TOTAL (Enter Total of lines 20 thru 28)	589,037,503	589,037,503		

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) 12/31/2012	Year/Period of Report 2012/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 was	\$ 694,442
108 Accumulated Depreciation transferred to 111 along with asset transfer	(23,493)
Land Gains on Disposition	(11,075)

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, 2011	273,672,915	90,760,514	164,371,994	32,228,435	561,033,858
January 31, 2012	275,490,970	91,075,088	165,098,944	31,933,481	563,598,483
February 29, 2012	277,045,395	91,058,266	165,828,562	32,262,559	566,194,782
March 31, 2012	278,816,345	91,323,698	166,495,311	32,566,603	569,201,957
April 30, 2012	280,382,454	91,663,931	167,162,355	32,884,546	572,093,286
May 31, 2012	278,945,747	92,018,633	167,697,809	33,189,257	571,851,446
June 30, 2012	280,549,722	92,373,237	168,534,968	33,219,283	574,677,210
July 31, 2012	282,204,723	92,737,436	169,298,183	33,535,103	577,775,445
August 31, 2012	283,485,862	93,108,972	169,993,958	33,634,053	580,222,845
September 30, 2012	285,183,356	93,496,969	170,643,189	33,982,463	583,305,977
October 31, 2012	286,425,213	93,926,917	171,320,167	33,850,600	585,522,897
November 30, 2012	286,810,400	94,402,801	172,052,175	33,751,021	587,016,397
December 31, 2012	288,171,132	94,847,883	172,765,161	33,253,327	589,037,503
13-month average for rate-making	281,321,864	92,522,642	168,558,675	33,099,287	575,502,468

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

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Not applicable			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 \$	0	TOTAL	

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
				3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
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				20
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				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
				42

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)	11,388,594	11,011,796	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)	5,571,420	5,730,143	Production
8	Transmission Plant (Estimated)	3,983,548	4,159,175	Various
9	Distribution Plant (Estimated)	6,206,763	6,775,350	Various
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	285,266	302,639	Fleet Service
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	16,046,997	16,967,307	
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)	27,435,591	27,979,103	

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) 12/31/2012	Year/Period of Report 2012/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

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

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

Production Plant (estimated)	
December 31, 2011	5,571,420
January 31, 2012	5,682,557
February 29, 2012	5,640,686
March 31, 2012	5,757,016
April 30, 2012	5,717,446
May 31, 2012	5,713,785
June 30, 2012	5,682,898
July 31, 2012	5,734,467
August 31, 2012	5,676,049
September 30, 2012	5,763,383
October 31, 2012	5,738,691
November 30, 2012	5,669,744
December 31, 2012	5,730,143
13-month average for rate-making	5,698,330

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

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

Transmission Plant (estimated)	
December 31, 2011	3,983,548
January 31, 2012	4,093,546
February 29, 2012	4,127,850
March 31, 2012	4,022,560
April 30, 2012	3,991,985
May 31, 2012	3,982,784
June 30, 2012	3,934,341
July 31, 2012	3,942,619
August 31, 2012	4,096,777
September 30, 2012	4,083,728
October 31, 2012	4,000,666
November 30, 2012	4,072,001
December 31, 2012	4,159,175
13-month average for rate-making	4,037,814

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

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

Distribution Plant (estimated)	
December 31, 2011	6,206,763
January 31, 2012	6,070,969
February 29, 2012	6,654,227
March 31, 2012	7,002,538

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) 12/31/2012	Year/Period of Report 2012/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

April 30, 2012	7,094,487
May 31, 2012	6,652,971
June 30, 2012	6,384,805
July 31, 2012	6,416,513
August 31, 2012	6,365,013
September 30, 2012	6,301,605
October 31, 2012	6,536,112
November 30, 2012	6,438,911
December 31, 2012	6,775,350
13-month average for rate-making	6,530,790

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

Consists of parts inventory at the Fleet Service Department.

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		2013	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	35,957.00		14,054.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
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	12,533.00			
19	Other:				
20	Surrender: EPA Adjust				
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	23,424.00		14,054.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	202.96		202.96	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	202.96			
40	Balance-End of Year			202.96	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	202.96	136		
45	Gains	202.96	136		
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2014		2015		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		443,523.00		1
								2
								3
				14,054.00		14,054.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						12,533.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
14,054.00		14,054.00		379,458.00		445,044.00		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	26	405.92	162	44
				202.96	26	405.92	162	45
								46

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		2013	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
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				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2014		2015		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
								36
								37
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								41
								42
								43
								44
								45
								46

Name of Respondent

Otter Tail Power Company

This Report Is:

(1) An Original

(2) A Resubmission

Date of Report

(Mo, Da, Yr)

12/31/2012

Year/Period of Report

End of 2012/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	Not applicable					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent
Otter Tail Power Company

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

Date of Report
(Mo, Da, Yr)
12/31/2012

Year/Period of Report
End of 2012/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 cancelled	2,202,222		See Note	1,294,574	907,648
22	project - ND					
23	(North Dakota PSC order					
24	issued June 25, 2010)					
25						
26	Big Stone II cancelled	2,638,906		See Note	494,991	2,143,915
27	project - MN					
28	(Minnesota PUC order					
29	issued April 25, 2011)					
30						
31	Big Stone II cancelled	911,349		407	100,332	811,017
32	project - SD					
33	(South Dakota PUC order					
34	issued April 21, 2011)					
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	5,752,477			1,889,897	3,862,580

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) 12/31/2012	Year/Period of Report 2012/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. The amortization period is August 2010 through July 2013.

Schedule Page: 230 Line No.: 26 Column: d

Accounts 407 and 419 were used.

Schedule Page: 230 Line No.: 26 Column: e

This is Minnesota amortization, with interest. The amortization period is October 2011 through September 2016.

Schedule Page: 230 Line No.: 31 Column: e

This is South Dakota amortization. The amortization period is February 2011 through January 2021.

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	Transmission Studies				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	Generation Studies				
22	GS5M Interconnection Facility	228	456	204	456
23	GS5TB Interconnection Facility	2,997	456	2,701	456
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Deferred Income Tax Adjustments					
2	Due to ASC 740 on:					
3	Property/Non Property Related Items	2,382,170		282	690,842	1,691,328
4						
5						
6						
7	Asset Retirement Obligation Capitalized					
8	Hoot Lake Plant	1,375,012	127,543			1,502,555
9	Big Stone Plant	318,440	37,512			355,952
10	Coyote Station	1,496,235	143,877			1,640,112
11	Wind Generation - Langdon	225,123	61,883			287,006
12	Wind Generation - Ashtabula	136,784	51,454			188,238
13	Wind Generation - Luverne	110,067	53,067			163,134
14						
15	Derivatives-Marked to Market Losses	15,957,202	18,268,370	244	16,227,014	17,998,558
16						
17	ND MISO Costs Deferred *	342,927		555	342,927	
18						
19	MN Renewable Resource Rider	2,767,201	420,724	See Note	2,272,616	915,309
20	ND Renewable Resource Rider	2,109,725	2,856,071	See Note	3,346,508	1,619,288
21						
22	ESSRP	2,641,657	463,855	228.3	182,959	2,922,553
23						
24	Pension	91,327,142	13,794,018	228.3	5,203,824	99,917,336
25						
26	Rate Case Expense Deferral *	1,005,863		407	720,694	285,169
27						
28	Holding Co. Formation *	137,742		407	55,200	82,542
29						
30	Asset Based Margin Sharing	138,392		See Note	138,392	
31						
32	MN Transmission Revenue Rider	252,361	1,786,066	See Note	686,775	1,351,652
33	ND Transmission Revenue Rider	518,179	809,082	See Note	1,217,446	109,815
34	SD Transmission Revenue Rider	113,634	38,583	See Note	149,698	2,519
35						
36	Post Retirement Medical Benefits	8,408,923	8,377,573	228.3	1,677,452	15,109,044
37						
38	Conservation Improvement Program - MN	7,395,841	3,418,953	186	4,682,410	6,132,384
39	Energy Efficiency Program - SD	45,767	228,507	186	140,078	134,196
40						
41						
42	* See footnote 3 for amortization period					
43						
44	TOTAL	139,206,387	50,937,138		37,734,835	152,408,690

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) 12/31/2012	Year/Period of Report 2012/Q4
FOOTNOTE DATA			

Schedule Page: 232 Line No.: 19 Column: d

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

Schedule Page: 232 Line No.: 20 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.

Schedule Page: 232 Line No.: 34 Column: d

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

MISCELLANEOUS DEFERRED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	Conservation Improvement					
2	Programs - MN		4,816,228	182.3	4,816,228	
3						
4	Energy Efficiency					
5	Program - SD		309,911	182.3	309,911	
6						
7	Purchase Card Accrual	156,707	2,702,187	186	2,690,188	168,706
8						
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42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	156,707				168,706

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	226,284
4	Medical Insurance Reserve		
5	Injuries and Damages Reserve		
6	See Note Below	109,206,956	115,749,927
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	109,433,240	115,976,211
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)	109,433,240	115,976,211

Notes

NOTES

Post Retirement Benefits	17,014,169	19,088,780
Executive Supplemental Pension	4,722,778	4,579,900
Reserve for Bad Debts	326,366	333,551
Accrued Vacation Pay	1,402,795	1,378,633
Capitalized Int. on Construction	4,297,187	4,538,375
Post Employment Benefits	278,509	362,262
Corporate Insurance Reserve	1,374	-
Nonqualified Retirement Savings	271,487	212,679
Gain From Breck Sale	231,087	-
Reserve for Loan Pools	17,492	10,802
Capitalized A & G	4,722,074	4,206,441
Customer Rebates Capitalized	133,980	113,172
Asbestos Removal Costs Capitalized	3,764	1,401
Stock Incentives	144,480	134,770
Mapleton Land	14,350	-
CIAC Capitalized	214,985	192,358
BSII Discount	232,462	132,802
Unicap Adjustment	34,990	37,332
Medicare Part D	297,303	351,908
Executive Stock Incentive Plan	(264,012)	-
Charitable Contributions	713,356	860,426
FIN 48 Tax Uncertainties	265,557	-
South Dakota Flow-Through Items	256,397	249,936
ND NOL Carryforward	7,726,502	7,445,766
Wind Energy Income Tax Credits-ND	44,370,161	44,172,134
SFAS 109 Unamortized ITC	3,379,678	2,553,864
SFAS 109 Recognition of Regulatory Assets (Liab.)	3,159,841	3,167,609
Wind Production Tax Credit Deferral (Asset)	15,237,844	21,625,026
	-----	-----
	109,206,956	115,749,927

CAPITAL STOCKS (Account 201 and 204)

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

2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201 (Par)			
2	Common Stock	50,000,000	5.00	
3				
4				
5	TOTAL COMMON	50,000,000		
6				
7	Cumulative Preferred	1,500,000		
8	Cumulative Preference	1,000,000		
9	TOTAL PREFERRED	2,500,000		
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Name of Respondent
Otter Tail Power Company

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

Date of Report
(Mo, Da, Yr)
12/31/2012

Year/Period of Report
End of 2012/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

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

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

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

Line No.	Item (a)	Amount (b)
1	Parent company investment in Otter Tail Power Company	209,861,391
2	Additional parent investment	20,000,000
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40	TOTAL	229,861,391

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) 12/31/2012	Year/Period of Report End of <u>2012/Q4</u>
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CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Shares	
2		
3	Not applicable	
4		
5		
6		
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11		
12		
13	Cumulative Preferred Shares	
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221 - Bonds		
2	2021 Series 4.63% Notes	140,000,000	887,622
3	2017 Series Pollution Control Refund-BSP	5,185,000	460,795
4	2022 Series Pollution Control Refund-CYT	20,790,000	2,045,091
5	Senior Unsecured Notes 6.47%, Series D	50,000,000	665,975
6			
7	Senior Unsecured Notes 6.37%, Series C	42,000,000	540,768
8			
9	Senior Unsecured Notes 6.15%, Series B	30,000,000	386,988
10	Senior Unsecured Notes 5.95%, Series A	33,000,000	424,856
11	Account 222 - Reacquired Bonds - None		
12	Account 223 - Advances from associated companies		
13	5.33% Notes-Otter Tail Corporation	6,000,000	
14			
15	7.21% Notes-Otter Tail Corporation	2,500,000	
16			
17	7.62% Notes-Otter Tail Corporation	3,000,000	
18			
19	9.35% Notes-Otter Tail Corporation	4,000,000	
20			
21	Account 224 Other Long Term Debt - None		
22			
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32			
33	TOTAL	336,475,000	5,412,095

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) 12/31/2012	Year/Period of Report 2012/Q4
FOOTNOTE DATA			

Schedule Page: 256 Line No.: 27 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.

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)	38,472,974
2		
3		
4	Taxable Income Not Reported on Books	
5	Interest capitalized on construction	1,005,556
6	Net gain from property retirements	559,116
7	Miscellaneous taxable items	
8	Conservation Improvement Programs	48,334
9	Deductions Recorded on Books Not Deducted for Return	
10	Add back federal income taxes (incl. deferreds and ITC adjustment)	6,962,272
11	Provision for reserves	11,201,578
12	Miscellaneous unallowed deductions	47,514,935
13		
14	Income Recorded on Books Not Included in Return	
15	Tax exempt interest	7,028
16	Equity in earnings of subsidiaries	
17	Wind rider revenue	9,490,291
18	Miscellaneous income not taxable	656,067
19	Deductions on Return Not Charged Against Book Income	
20	Excess tax depreciation over book depreciation	33,297,980
21	Removal costs	2,933,457
22	Charges to reserves	6,060,837
23	Leveraged ESOP deduction	1,875,571
24	Sec. 481(a) cap to repair basis adjustments	9,947,847
25	Miscellaneous other deductions	36,243,571
26		
27	Federal Tax Net Income	5,252,116
28	Show Computation of Tax:	
29	Federal tax (Line 27 x 35%)	1,838,241
30	Tax (credits) and adjustments	-1,838,241
31	Prior period adjustments	-1,048,126
32	Total federal income tax	-1,048,126
33		
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Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Power Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2012	2012/Q4
FOOTNOTE DATA			

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

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

Otter Tail Power Company is a member of an affiliated group which will file a consolidated Federal Income Tax Return for the year 2012. The other members of the affiliated group and their respective federal income tax provisions are as follows:

1	Otter Tail Corporation-Corporate	(9,668,724)
2	Varistar Corporation	(1,484,183)
3	DMI Industries, Inc.	(13,065,966)
4	Moorhead Electric, Inc.	148,252
5	DMS Health Technologies, Inc.	(30,429)
6	DMS Imaging, Inc.	(87,782)
7	BTD Manufacturing, Inc.	5,733,637
8	Northern Pipe Products, Inc.	4,388,752
9	Vinyltech Corporation	2,982,575
10	Otter Tail Energy Services Company	(324,456)
11	T. O. Plastics, Inc.	1,379,227
12	ShoreMaster, Inc.	(154,765)
13	Galva Foam Marine Industries, Inc.	(1,558,941)
14	Otter Tail Assurance Limited	(125,952)
15	Aevenia, Inc.	666,678
16	Foley Company	(5,177,164)
17	Shoreline Industries, Inc.	292,952
18	Aviva Sports, Inc.	(408,022)
19	Miller Welding & Iron Works, Inc.	(1,695,833)
20	DMS Health Technologies - Canada	11,116
21	DMS Topline Medical, Inc.	101,039

	Total	(18,077,987)

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.

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			-1,048,126	-1,527,621	
3	Unemployment	10,929		35,135	45,491	
4	FICA			4,267,449	4,267,449	
5						
6	MINNESOTA					
7	Property	5,800,000		6,441,781	5,816,780	
8	Income			756,079	756,079	
9	Unemployment	1,532		93,636	93,443	
10						
11	NORTH DAKOTA					
12	Property	2,749,998		2,375,626	2,575,624	
13	Income			377,224	377,224	
14	Unemployment	174		12,362	12,260	
15	Coal Conversion	183,135		692,126	754,964	
16						
17	SOUTH DAKOTA					
18	Property	1,304,080		1,253,713	1,167,793	
19	Unemployment	35		2,762	2,702	
20						
21	OTHER STATES					
22	Income					
23	Railcar	23,728		47,822	52,049	
24						
25						
26						
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32						
33						
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35						
36						
37						
38						
39						
40						
41	TOTAL	10,073,611		15,307,589	14,394,237	

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
479,495		-3,080,962			2,032,836	2
573					35,135	3
					4,267,449	4
						5
						6
6,425,001		6,441,781				7
		235,579			520,500	8
1,725					93,636	9
						10
						11
2,550,000		2,326,541			49,085	12
		120,870			256,354	13
276					12,362	14
120,297		692,126				15
						16
						17
1,390,000		1,253,713				18
95					2,762	19
						20
						21
						22
19,501					47,822	23
						24
						25
						26
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						40
10,986,963		7,989,648			7,317,941	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) 12/31/2012	Year/Period of Report 2012/Q4
FOOTNOTE DATA			

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

Account 409.2

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

Account 184

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

Account 184

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

Account 409.2

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

Account 184

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

Account 408.2 \$5,393; Account 921 \$43,692

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

Account 409.2

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

Account 184

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

Account 184

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

Account 151

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%	30,036,422			411.4	1,161,989	
3	4%						
4	7%						
5	10%	3,145,327			411.4	720,375	
6							
7							
8	TOTAL	33,181,749				1,882,364	
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
28,874,433	25 Years		2
			3
			4
2,424,952	33.3 Years		5
			6
			7
31,299,385			8
			9
			10
			11
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Name of Respondent
Otter Tail Power Company

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

Date of Report
(Mo, Da, Yr)
12/31/2012

Year/Period of Report
End of 2012/Q4

OTHER DEFERRED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Prepaid Electric Revenue	520,038	456	237,767	183,903	466,174
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
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43						
44						
45						
46						
47	TOTAL	520,038		237,767	183,903	466,174

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

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amortizable property.

2. For other (Specify), include deferrals relating to other income and deductions.

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

NOTES

Name of Respondent

Otter Tail Power Company

This Report Is:

(1) An Original

(2) A Resubmission

Date of Report

(Mo, Da, Yr)

12/31/2012

Year/Period of Report

End of 2012/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
							3
							4
							5
							6
							7
							8
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							10
							11
							12
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							17
							18
							19
							20
							21

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) 12/31/2012	Year/Period of Report 2012/Q4
FOOTNOTE DATA			

Schedule Page: 272 Line No.: 17 Column: b
Not Applicable

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	256,756,331	27,940,583	9,391,421
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	256,756,331	27,940,583	9,391,421
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	256,756,331	27,940,583	9,391,421
10	Classification of TOTAL			
11	Federal Income Tax	220,229,166	23,392,953	7,459,777
12	State Income Tax	36,527,165	4,547,630	1,931,644
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
-54	109,772	182.3	1,307,935			273,887,732	2
							3
							4
-54	109,772		1,307,935			273,887,732	5
							6
							7
							8
-54	109,772		1,307,935			273,887,732	9
							10
29	91,648		1,097,228			234,973,495	11
-83	18,124		210,708			38,914,236	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) 12/31/2012	Year/Period of Report 2012/Q4
FOOTNOTE DATA			

Schedule Page: 274 Line No.: 2 Column: h
Adjustment due to ASC 740

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Accum. Deferred Income Tax			
4	Other Utility Operations	14,568,688	182,713	1,788,402
5				
6	Accum. Deferred Income Tax			
7	Nonutility & Other	452,251		
8				
9	TOTAL Electric (Total of lines 3 thru 8)	15,020,939	182,713	1,788,402
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)	15,020,939	182,713	1,788,402
20	Classification of TOTAL			
21	Federal Income Tax	11,888,911	144,615	1,415,502
22	State Income Tax	3,132,028	38,098	372,900
23	Local Income Tax			

NOTES

Name of Respondent
Otter Tail Power Company

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

Date of Report
(Mo, Da, Yr)
12/31/2012

Year/Period of Report
End of 2012/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS				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
		228.3	104,256	182.3	624,864	13,483,607	4
							5
							6
709,144	307,413					853,982	7
							8
709,144	307,413		104,256		624,864	14,337,589	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
709,144	307,413		104,256		624,864	14,337,589	19
							20
561,280	243,314		82,518		494,574	11,348,046	21
147,864	64,099		21,738		130,290	2,989,543	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) 12/31/2012	Year/Period of Report 2012/Q4
FOOTNOTE DATA			

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

Adjustment due to ASC715-60

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

Adjustment due to ACS740

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

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

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	3,379,173	190	825,812		2,553,361
2	ASC 740					
3						
4	Minnesota Portion of Gain on Sale of Wahpeton	122,680	407.4	5,576		117,104
5	Division Office (Amortization period: 34 years)					
6						
7	Regulatory Liabilities - Derivatives	96,542	175	89,131	210,038	217,449
8						
9	Margin Sharing - SD	53,664	See Note	801	3,569	56,432
10						
11	MN Transmission Revenue Rider	28,568	See Note	28,568	489,115	489,115
12						
13	SD Transmission Revenue Rider		See Note	38,583	38,583	
14						
15						
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41	TOTAL	3,680,627		988,471	741,305	3,433,461

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) 12/31/2012	Year/Period of Report 2012/Q4
FOOTNOTE DATA			

Schedule Page: 278 Line No.: 9 Column: c
Accounts 440, 442, 444, and 445 were credited.

Schedule Page: 278 Line No.: 11 Column: c
Accounts 440, 442, 444, and 445 were credited.

Schedule Page: 278 Line No.: 13 Column: c
Accounts 440, 442, 444, and 445 were credited.

ELECTRIC OPERATING REVENUES (Account 400)

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

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	104,144,744	105,997,246
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	120,824,857	118,749,830
5	Large (or Ind.) (See Instr. 4)	74,442,916	74,430,490
6	(444) Public Street and Highway Lighting	3,452,048	3,329,067
7	(445) Other Sales to Public Authorities	2,635,752	2,759,500
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	305,500,317	305,266,133
11	(447) Sales for Resale	12,951,359	14,518,307
12	TOTAL Sales of Electricity	318,451,676	319,784,440
13	(Less) (449.1) Provision for Rate Refunds		3,932,908
14	TOTAL Revenues Net of Prov. for Refunds	318,451,676	315,851,532
15	Other Operating Revenues		
16	(450) Forfeited Discounts	556,298	573,772
17	(451) Miscellaneous Service Revenues	413,076	411,096
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	571,229	682,411
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	9,131,131	8,084,155
22	(456.1) Revenues from Transmission of Electricity of Others	13,607,785	8,365,540
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	24,279,519	18,116,974
27	TOTAL Electric Operating Revenues	342,731,195	333,968,506

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
1,253,567	1,315,798	101,996	101,792	2
				3
1,555,573	1,596,350	26,476	26,418	4
1,367,050	1,311,133	52	53	5
26,300	26,207	404	397	6
38,299	42,149	595	590	7
				8
				9
4,240,789	4,291,637	129,523	129,250	10
2,135,159	2,496,462			11
6,375,948	6,788,099	129,523	129,250	12
				13
6,375,948	6,788,099	129,523	129,250	14

Line 12, column (b) includes \$ -2,892,987 of unbilled revenues.
 Line 12, column (d) includes 25,271 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) 12/31/2012	Year/Period of Report 2012/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)	\$ 413,076	\$ 411,096
	-----	-----
Total	\$ 413,076	\$ 411,096
	=====	=====

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

Description of Revenue	Current Year	Prior Year
Sale of steam	\$ 1,849,579	\$ 2,101,593
Integrated transmission deficiency payments	4,929,695	3,409,270
All others (under \$250,000 each)	2,351,857	2,573,292
	-----	-----
Total	\$ 9,131,131	\$8,084,155
	=====	=====

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Not applicable.				
2					
3					
4					
5					
6					
7					
8					
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36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential-440					
2	Residential Service					
3	9.01	875,547	83,551,222	95,683	9,150	0.0954
4						
5	Residential Service (Ctrl'd Demand					
6	9.02	142,651	10,158,254	6,334	22,521	0.0712
7						
8	Water Heating Ctrl'd (Off-Peak)					
9	14.01	41,219	2,977,689	16,902	2,439	0.0722
10				-16,902		
11	Controlled Service					
12	14.04,14.05,14.06,14.07	172,681	8,541,053	12,505	13,809	0.0495
13				-12,505		
14	Fixed Time of Delivery Service					
15	14.07	3,454	135,855	307	11,251	0.0393
16				-307		
17	Outdoor lighting-energy only					
18	11.03	144	11,254	12	12,000	0.0782
19				-12		
20	Outdoor Lighting					
21	11.04	3,993	536,737	361	11,061	0.1344
22				-361		
23	Small power producer rider					
24	12.01		290	7		
25				-7		
26	Conservation Imp Prog Rev		-1,273,313			
27	N/A					
28						
29	SUBTOTAL Billed	1,239,689	104,639,041	102,017	12,152	0.0844
30	Unbilled Rev (See Instr. 6)	13,878	-494,297			-0.0356
31	TOTAL - 440	1,253,567	104,144,744	102,017	12,288	0.0831
32						
33	Column D Lines 9,12,15,18,21&24					
34	customers are also served					
35	under other residential service.					
36						
37						
38						
39						
40						
41	TOTAL Billed	4,215,518	308,393,304	132,014	31,932	0.0732
42	Total Unbilled Rev.(See Instr. 6)	25,271	-2,892,987	0	0	-0.1145
43	TOTAL	4,240,789	305,500,317	132,014	32,124	0.0720

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Commercial & Industrial-442					
2	General Service					
3	10.01,10.02	723,320	64,946,692	24,275	29,797	0.0898
4						
5	Farm Service					
6	9.03	57,886	4,994,345	2,758	20,988	0.0863
7						
8	Large General Service					
9	10.03	607,598	39,714,522	370	1,642,157	0.0654
10						
11	Real Time Pricing Rider					
12	14.02	36,267	1,335,254	1	36,267,000	0.0368
13						
14	Large Gen. Srv. (Time of Day)					
15	10.05	705,579	41,527,013	94	7,506,160	0.0589
16						
17	Large General Service Rider					
18	14.03	26,314	1,168,212	14	1,879,571	0.0444
19						
20	Water Heating Ctrlld (Off-Peak)					
21	14.01	2,179	148,675	559	3,898	0.0682
22				-559		
23	Controlled Service					
24	14.04,14.05,14.06,14.07	177,464	7,505,886	4,681	37,912	0.0423
25				-4,681		
26	Fixed Time of Delivery Service					
27	14.07	19,050	705,809	511	37,280	0.0371
28				-511		
29	Irrigation Service					
30	11.02	7,358	504,256	281	26,185	0.0685
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	4,215,518	308,393,304	132,014	31,932	0.0732
42	Total Unbilled Rev.(See Instr. 6)	25,271	-2,892,987	0	0	-0.1145
43	TOTAL	4,240,789	305,500,317	132,014	32,124	0.0720

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Commercial and Industrial - cntd					
2	Commercial Time of Use					
3	10.04	531,949	36,240,128	559	951,608	0.0681
4						
5	Outdoor Lighting - Energy Only					
6	11.03	1,953	155,156	252	7,750	0.0794
7				-252		
8	Outdoor Lighting					
9	11.04	14,408	1,833,090	258	55,845	0.1272
10				-258		
11	Standby Service - Option A Firm					
12	11.01	125	14,399	5	25,000	0.1152
13						
14	Small Power Producer Rider					
15	12.01		547	17		
16				-17		
17	Conservation Imp Prog Rev		-3,111,062			
18	N/A					
19						
20	SUBTOTAL Billed	2,911,450	197,682,922	28,357	102,671	0.0679
21	Unbilled Rev (See Instr. 6)	11,173	-2,415,149			-0.2162
22	TOTAL - 442	2,922,623	195,267,773	28,357	103,065	0.0668
23						
24						
25						
26	Column D Lines 6,9 & 15					
27	customers are also served under					
28	other commerical service.					
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	4,215,518	308,393,304	132,014	31,932	0.0732
42	Total Unbilled Rev.(See Instr. 6)	25,271	-2,892,987	0	0	-0.1145
43	TOTAL	4,240,789	305,500,317	132,014	32,124	0.0720

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Streetlighting - 444					
2	Outdoor Lighting-Energy Only					
3	11.03	6,902	526,247	234	29,496	0.0762
4				-234		
5	Outdoor lighting					
6	11.04	19,348	2,964,699	357	54,196	0.1532
7						
8	Conservation Imp Prog Rev		-22,459			
9	N/A					
10						
11	Subtotal billed	26,250	3,468,487	357	73,529	0.1321
12	Unbilled Revenue	50	-16,439			-0.3288
13	TOTAL - 444	26,300	3,452,048	357	73,669	0.1313
14						
15	Other Public Authority-445					
16	Pumping and Sirens					
17	11.05,11.06	38,129	2,639,371	1,283	29,719	0.0692
18	Conservation Imp Prog Rev		-36,517			
19	Unbilled Revenue	170	32,898			0.1935
20	TOTAL - 445	38,299	2,635,752	1,283	29,851	0.0688
21						
22	Revenue from Fuel Adjustment					
23	Clause is reported in footnote.					
24						
25	Column D, Line 3					
26	customers are also served under					
27	other commercial service.					
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	4,215,518	308,393,304	132,014	31,932	0.0732
42	Total Unbilled Rev.(See Instr. 6)	25,271	-2,892,987	0	0	-0.1145
43	TOTAL	4,240,789	305,500,317	132,014	32,124	0.0720

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) 12/31/2012	2012/Q4
FOOTNOTE DATA			

Schedule Page: 304 Line No.: 26 Column: c

Conservation Improvement Programs revenues that are not allocated to any specific rate schedule.

Schedule Page: 304.2 Line No.: 17 Column: c

Conservation Improvement Programs revenues that are not allocated to any specific rate schedule.

Schedule Page: 304.3 Line No.: 8 Column: c

Conservation Improvement Programs revenues that are not allocated to any specific rate schedule.

Schedule Page: 304.3 Line No.: 18 Column: c

Conservation Improvement Programs revenues that are not allocated to any specific rate schedule.

Schedule Page: 304.3 Line No.: 22 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	\$ 647,761
9.02	Residential service (control demand)	(64,380)
14.01	Water heating - controlled (off peak)	62,261
14.04,14.05,14.06,14.07	Controlled service	(35,573)
14.07	Fixed time of delivery service	3,274
11.03	Outdoor lighting - energy only	(330)
11.04	Outdoor lighting	<u>2,593</u>
Total Residential		615,605

Commercial and industrial - 442

10.01,10.02	General service	334,973
9.03	Farm service	98,079
10.03	Large general service	(2,342,017)
14.02	Real time pricing rider	(8,184)
10.05	Large general service (time of day)	989,469
14.03	Large general service rider	11,814
14.01	Water heating - controlled (off-peak)	6,423
14.04,14.05,14.06,14.07	Controlled service	(27,379)
14.07	Fixed time of delivery service	12,977
11.02	Irrigation service	6,411
10.04	Commercial time of use	3,776,777
11.03	Outdoor lighting - energy only	2,341
11.04	Outdoor lighting	(1,398)
11.01	Standby service-option A firm	<u>(492)</u>
Total commercial and industrial		2,859,794

Streetlighting - 444

11.03	Outdoor lighting - energy only	3,488
11.04	Outdoor lighting	<u>3,831</u>
Total streetlighting		7,319

Other public authority - 445

11.05,11.06	Pumping and sirens	<u>30,932</u>
-------------	--------------------	---------------

TOTAL \$ 3,513,650
=====

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	0.079	NA	NA
3	Newfolden, MN	RQ	174	0.563	NA	NA
4	Nielsville, MN	RQ	175	0.042	NA	NA
5	Shelly, MN	RQ	176	0.173	NA	NA
6						
7						
8	NON-RQ SALES					
9	Ameren Energy Marketing Co	OS	180	NA	NA	NA
10	Ameren Energy Marketing Co	SF	180	50	NA	NA
11	American Electric Power Service Corp	OS	180	NA	NA	NA
12	Ameren UE (Union Electric Co)	OS	180	NA	NA	NA
13	Cargill Power Markets, LLC	OS	180	NA	NA	NA
14	Constellation Energy Commodities Group.	OS	180	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

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	Wisconsin Power and Light	OS	180	NA	NA	NA
2	RBC Capital Markets Corporation	OS	180	NA	NA	NA
3	Midwest ISO Energy Market	OS	180	NA	NA	NA
4	Non-asset based sales	OS	180	NA	NA	NA
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447) (Continued)

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

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

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

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

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

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

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

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

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

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
					1
149	4,124	4,476	969	9,569	2
2,341	32,441	79,611	13,168	125,220	3
63	2,861	1,985	235	5,081	4
663	12,106	21,477	3,278	36,861	5
					6
					7
					8
17,600		-49,464		-49,464	9
	11,000			11,000	10
55,200		-24,763		-24,763	11
26,800		63,185		63,185	12
19,600		104,955		104,955	13
52,000		-281,396		-281,396	14
3,216	51,532	107,549	17,650	176,731	
2,131,943	11,210	12,763,418	0	12,774,628	
2,135,159	62,742	12,870,967	17,650	12,951,359	

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)		
2,000		3,579		3,579	1
242,750		-791,223		-791,223	2
	210			210	3
2,400		-597		-597	4
131,760		1,403,545		1,403,545	5
1,600		7,714		7,714	6
18,450		63,506		63,506	7
8,400		284,960		284,960	8
56,000		1,680,000		1,680,000	9
1,200		-1,691		-1,691	10
254,945		2,811,204		2,811,204	11
5,600		155,608		155,608	12
14,000		3,536		3,536	13
400		29,579		29,579	14
3,216	51,532	107,549	17,650	176,731	
2,131,943	11,210	12,763,418	0	12,774,628	
2,135,159	62,742	12,870,967	17,650	12,951,359	

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)		
70,400		161,303		161,303	1
587,600		3,337,899		3,337,899	2
566,438		12,774,206		12,774,206	3
-3,200		-8,972,227		-8,972,227	4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
3,216	51,532	107,549	17,650	176,731	
2,131,943	11,210	12,763,418	0	12,774,628	
2,135,159	62,742	12,870,967	17,650	12,951,359	

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) 12/31/2012	Year/Period of Report 2012/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

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

Lines 2 - 5 are fuel adjustment charges.

Schedule Page: 310 Line No.: 10 Column: h

July through August 2012

Schedule Page: 310.1 Line No.: 3 Column: h

July 2012

Schedule Page: 310.2 Line No.: 4 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.

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	1,826,859	1,756,327
5	(501) Fuel	64,141,238	67,279,042
6	(502) Steam Expenses	2,914,839	2,758,351
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,576,896	2,505,471
10	(506) Miscellaneous Steam Power Expenses	4,375,501	4,911,042
11	(507) Rents	1,500	683
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	75,836,833	79,210,916
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	816,833	778,528
16	(511) Maintenance of Structures	717,803	597,892
17	(512) Maintenance of Boiler Plant	6,655,306	7,404,372
18	(513) Maintenance of Electric Plant	1,390,201	1,155,193
19	(514) Maintenance of Miscellaneous Steam Plant	1,113,359	1,005,810
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	10,693,502	10,941,795
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	86,530,335	90,152,711
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	37,235	10,208
45	(536) Water for Power		
46	(537) Hydraulic Expenses	20,438	26,418
47	(538) Electric Expenses	97,790	119,352
48	(539) Miscellaneous Hydraulic Power Generation Expenses	22,504	28,534
49	(540) Rents	54	
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	178,021	184,512
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	2,907	3,653
54	(542) Maintenance of Structures	3,651	23,082
55	(543) Maintenance of Reservoirs, Dams, and Waterways	281,218	332,332
56	(544) Maintenance of Electric Plant	8,740	8,708
57	(545) Maintenance of Miscellaneous Hydraulic Plant	319	18,714
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	296,835	386,489
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	474,856	571,001

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	193,199	185,639
63	(547) Fuel	2,536,985	2,245,008
64	(548) Generation Expenses	2,598,726	2,426,405
65	(549) Miscellaneous Other Power Generation Expenses	668,907	642,814
66	(550) Rents	547,607	536,158
67	TOTAL Operation (Enter Total of lines 62 thru 66)	6,545,424	6,036,024
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	37,417	38,542
70	(552) Maintenance of Structures	65,537	5,010
71	(553) Maintenance of Generating and Electric Plant	537,672	350,629
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	22,475	3,110
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	663,101	397,291
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	7,208,525	6,433,315
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	49,183,767	43,451,182
77	(556) System Control and Load Dispatching	425,618	514,315
78	(557) Other Expenses	763,728	884,215
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	50,373,113	44,849,712
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	144,586,829	142,006,739
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	410,161	419,623
84			
85	(561.1) Load Dispatch-Reliability	76,149	59,639
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,380,398	2,324,061
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	602,731	581,344
90	(561.6) Transmission Service Studies	584	
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	303,936	324,336
94	(563) Overhead Lines Expenses	536,080	269,815
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	5,745,570	2,523,511
97	(566) Miscellaneous Transmission Expenses	1,363,146	1,107,558
98	(567) Rents	43,141	56,514
99	TOTAL Operation (Enter Total of lines 83 thru 98)	11,461,896	7,666,401
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	192,590	342,282
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	97,269	81,304
104	(569.2) Maintenance of Computer Software	586,489	627,996
105	(569.3) Maintenance of Communication Equipment	101,234	88,176
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,126,813	1,352,195
108	(571) Maintenance of Overhead Lines	1,836,227	1,519,652
109	(572) Maintenance of Underground Lines	216	
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	3,940,838	4,011,605
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	15,402,734	11,678,006

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	1,278,103	1,167,868
117	(575.3) Transmission Rights Market Facilitation	272,907	235,742
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)	1,551,010	1,403,610
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		10,138
127	(576.3) Maintenance of Computer Software	317,233	321,358
128	(576.4) Maintenance of Communication Equipment		70
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)	317,233	331,566
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	1,868,243	1,735,176
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	359,230	368,359
135	(581) Load Dispatching	257,567	309,731
136	(582) Station Expenses	212,466	270,851
137	(583) Overhead Line Expenses	309,255	312,904
138	(584) Underground Line Expenses	1,796,915	1,447,140
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	942,543	788,938
141	(587) Customer Installations Expenses	237,199	201,875
142	(588) Miscellaneous Expenses	2,931,874	2,857,539
143	(589) Rents	249,928	269,070
144	TOTAL Operation (Enter Total of lines 134 thru 143)	7,296,977	6,826,407
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	745,955	611,486
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	858,855	815,020
149	(593) Maintenance of Overhead Lines	3,892,582	3,977,648
150	(594) Maintenance of Underground Lines	1,051,040	1,034,717
151	(595) Maintenance of Line Transformers	78,494	72,130
152	(596) Maintenance of Street Lighting and Signal Systems	1,104,796	993,314
153	(597) Maintenance of Meters	740,152	676,108
154	(598) Maintenance of Miscellaneous Distribution Plant	99,305	79,496
155	TOTAL Maintenance (Total of lines 146 thru 154)	8,571,179	8,259,919
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	15,868,156	15,086,326
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	124,006	116,309
160	(902) Meter Reading Expenses	5,594,019	5,391,502
161	(903) Customer Records and Collection Expenses	5,857,780	5,481,465
162	(904) Uncollectible Accounts	598,000	405,753
163	(905) Miscellaneous Customer Accounts Expenses	328,188	348,236
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	12,501,993	11,743,265

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	658,971	542,639
168	(908) Customer Assistance Expenses	6,668,556	7,195,123
169	(909) Informational and Instructional Expenses	406,804	265,279
170	(910) Miscellaneous Customer Service and Informational Expenses	83,963	59,722
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	7,818,294	8,062,763
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	251,430	387,160
176	(913) Advertising Expenses	16,158	24,158
177	(916) Miscellaneous Sales Expenses	273,779	342,170
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	541,367	753,488
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	18,693,578	17,445,224
182	(921) Office Supplies and Expenses	4,536,852	3,921,483
183	(Less) (922) Administrative Expenses Transferred-Credit	1,752,389	2,270,409
184	(923) Outside Services Employed	1,050,131	793,902
185	(924) Property Insurance	2,155,325	2,408,016
186	(925) Injuries and Damages	1,441,111	1,012,535
187	(926) Employee Pensions and Benefits	2,218,402	3,665,092
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	855,803	1,852,029
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	364,304	601,317
192	(930.2) Miscellaneous General Expenses	693,835	757,750
193	(931) Rents	237,150	220,055
194	TOTAL Operation (Enter Total of lines 181 thru 193)	30,494,102	30,406,994
195	Maintenance		
196	(935) Maintenance of General Plant	1,793,879	2,865,915
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	32,287,981	33,272,909
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	230,875,597	224,338,672

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) 12/31/2012	Year/Period of Report 2012/Q4
FOOTNOTE DATA			

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

\$552,845 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

\$583,464 of the year-to-date expense recorded in Accounts 561 and 569 is designated as Account 561.BA expense.

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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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	AmerenUE	OS		NA	NA	NA
2	American Electric Power Service Corp	OS		NA	NA	NA
3	Ameren Energy Marketing Co.	OS		NA	NA	NA
4	Basin Electric Power Cooperative	OS		NA	NA	NA
5	Cargill Power Markets, LLC	OS		NA	NA	NA
6	Constellation Energy Commodities Group	OS		NA	NA	NA
7	DTE Energy Trading, Inc.	OS		NA	NA	NA
8	EDF Trading North America	OS		NA	NA	NA
9	Great River Energy	OS		NA	NA	NA
10	Great River Energy	SF		50	NA	NA
11	HD Electric Cooperative	OS		NA	NA	NA
12	Horizon Wind Energy LLC	OS		NA	NA	NA
13	MacQuarie Energy LLC	OS		NA	NA	NA
14	Manitoba Hydro Electric Board	OS		NA	NA	NA
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	MidAmerican Energy Company	OS		NA	NA	NA
2	Minnkota Power Cooperative	OS		NA	NA	NA
3	Minnkota Power Cooperative - Manvel Em	OS		NA	NA	NA
4	Minnesota Power Tie error	OS		NA	NA	NA
5	Montana Dakota Utilities - meter error	OS		NA	NA	NA
6	Northern States Power Company	OS		NA	NA	NA
7	The Energy Authority	OS		NA	NA	NA
8	Transalta Energy Marketing	OS		NA	NA	NA
9	Western Area Power Administration	OS		NA	NA	NA
10	Western Area Power Administration-WEC	OS		NA	NA	NA
11	WE Energies	SF		50	NA	NA
12	Beltrami Electric Cooperative	RQ		NA	NA	NA
13	Nodak Rural Electric Cooperative	RQ		NA	NA	NA
14	P K M Electric Cooperative	RQ		NA	NA	NA
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	NorthWestern Energy - NLE	RQ		NA	NA	NA
2	Red Lake Rural Electric Cooperative	RQ		NA	NA	NA
3	Lake Region Rural Electric Cooperative	RQ		NA	NA	NA
4	Redwood Electric	RQ		NA	NA	NA
5	Cass County Electric Cooperative	RQ		NA	NA	NA
6	Sioux Valley Energy	RQ		NA	NA	NA
7	North Central Electric Cooperative	RQ		NA	NA	NA
8	Dakota Valley Services	RQ		NA	NA	NA
9	City of Perham	RQ		NA	NA	NA
10	Dakota Magic Casino	RQ		NA	NA	NA
11	State Auto Insurance	RQ		NA	NA	NA
12	Kindred School	RQ		NA	NA	NA
13	Fleet Farm	RQ		NA	NA	NA
14	Valley Queen Cheese	OS		NA	NA	NA
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Stevens County Medical Center	OS		NA	NA	NA
2	City of Detroit Lakes	OS		NA	NA	NA
3	American Crystal Sugar	OS		NA	NA	NA
4	Energy Mtce. Service-Broadwind Srvcs,	OS		NA	NA	NA
5	Hendricks Wind I	OS		NA	NA	NA
6	Borderline Wind	OS		NA	NA	NA
7	University of Minnesota - Morris	OS		NA	NA	NA
8	FPL Energy ND II, LLC	OS		NA	NA	NA
9	FPL Energy ND II, LLC - curtailment	OS		NA	NA	NA
10	Langdon Wind, LLC	OS		NA	NA	NA
11	Turtle Mountain Community College	OS		NA	NA	NA
12	District 45 Methane	OS		NA	NA	NA
13	LacQui Parle School	OS		NA	NA	NA
14	Pembina Border Station	OS		NA	NA	NA
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	MN Co Generation	OS		NA	NA	NA
2	ND Co Generation	OS		NA	NA	NA
3	SD Co Generation	OS		NA	NA	NA
4	RBC Capital Markets Corporation	OS		NA	NA	NA
5	Midwest ISO Energy Market	OS		NA	NA	NA
6	Non-Asset Based Cost of Sales					
7	Miscellaneous Energy Market Changes					
8	Other ISO Energy Markets					
9						
10						
11						
12						
13						
14						
	Total					

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.

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

6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.

7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.

8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
26,800				93,038		93,038	1
46,100				12,426		12,426	2
17,600				-55,255		-55,255	3
3,818				86,767		86,767	4
24,000				25,402		25,402	5
168,800				759,002		759,002	6
1,200				3,827		3,827	7
89,600				78,749		78,749	8
1,600				-541		-541	9
			390,000			390,000	10
				14		14	11
131,760				1,376,609		1,376,609	12
223,150				86,426		86,426	13
800				-1,328		-1,328	14
3,340,134			2,166,522	46,881,017	136,229	49,183,768	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
1,600				-5,171		-5,171	1
70,400				-178,497		-178,497	2
2				150		150	3
-3,911				-14,821		-14,821	4
-415				-11,580		-11,580	5
438,345				8,105,455		8,105,455	6
3,200				122,600		122,600	7
16,000				-37,808		-37,808	8
416				37,440	43,001	80,441	9
29,973				996,595		996,595	10
			537,500			537,500	11
55,775			545,183	2,693,406	93,228	3,331,817	12
9,290			106,034	481,368		587,402	13
9,836			107,089	475,120		582,209	14
3,340,134			2,166,522	46,881,017	136,229	49,183,768	

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)	
14,234			136,079	619,234		755,313	1
8,583			95,441	395,439		490,880	2
11			745	1,099		1,844	3
46				2,102		2,102	4
			8,121	1,512		9,633	5
9				530		530	6
757				102,159		102,159	7
43				3,677		3,677	8
			19,580			19,580	9
			34,320			34,320	10
			10,080			10,080	11
			34,980			34,980	12
			9,240			9,240	13
			109,340			109,340	14
3,340,134			2,166,522	46,881,017	136,229	49,183,768	

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)	
			21,600			21,600	1
908			1,190	1,362		2,552	2
23				228		228	3
152				4,873		4,873	4
2,571				115,712		115,712	5
1,633				48,993		48,993	6
5,130				281,875		281,875	7
54,441				1,627,788		1,627,788	8
2,771				92,777		92,777	9
72,275				2,834,627		2,834,627	10
639				21,151		21,151	11
10,096				433,130		433,130	12
20				637		637	13
172				5,561		5,561	14
3,340,134			2,166,522	46,881,017	136,229	49,183,768	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
28				9,701		9,701	1
55				632		632	2
37				1,177		1,177	3
622,400				698,712		698,712	4
1,247,361				38,810,886		38,810,886	5
-70,000				-14,828,612		-14,828,612	6
				332,453		332,453	7
				132,209		132,209	8
							9
							10
							11
							12
							13
							14
3,340,134			2,166,522	46,881,017	136,229	49,183,768	

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) 12/31/2012	Year/Period of Report 2012/Q4
FOOTNOTE DATA			

Schedule Page: 326 Line No.: 10 Column: a

January through December 2012

Schedule Page: 326.1 Line No.: 9 Column: I

Load following charge

Schedule Page: 326.1 Line No.: 11 Column: a

January through December 2012

Schedule Page: 326.1 Line No.: 12 Column: I

Nomination charge

Schedule Page: 326.4 Line No.: 6 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 and 426.5, as appropriate. This amount represents the non-asset based cost of forward energy sales.

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

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

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

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

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

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

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
4	(1)	Badger, SD		1,349	1,291	1
4	(1)	Newfolden, MN		2,917	2,726	2
4	(1)	Nielsville, MN		667	623	3
4	(1)	Shelly, MN		1,913	1,788	4
4	(1)	Fort Totten, ND		153	144	5
4	(1)	Grafton, ND		4,596	4,336	6
4	(1)	Devils Lake, ND		578	540	7
4	(1)	Bottineau, ND		1,135	1,061	8
4	(1)	Wahpeton, ND		8,689	8,159	9
4	(1)	Belcourt, ND		2,191	2,067	10
4	(1)	Oakes, ND		30	29	11
See Footnote	(1)	Various Interconnect		223,689	209,055	12
		(1)		-29,897		13
		(1)		22,238		14
		(1)		36,753		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	277,001	231,819	

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.
8,853			8,853	1
25,004			25,004	2
7,948			7,948	3
16,690			16,690	4
1,243			1,243	5
23,002			23,002	6
6,014			6,014	7
10,859			10,859	8
90,945			90,945	9
28,714			28,714	10
711			711	11
	209,055		209,055	12
				13
				14
				15
		13,178,747	13,178,747	16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
219,983	209,055	13,178,747	13,607,785	

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2012	Year/Period of Report 2012/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

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

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

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

Various Companies

Miscellaneous losses - mwh received

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

Midwest Independent System Operator Transmission

Schedule 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

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1	Not Applicable				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
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39					
40	TOTAL				

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to-Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Megawatt-hours Received (c)	Megawatt-hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	Otter Tail Power Co.	FNS					1,472,417	1,472,417
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL						1,472,417	1,472,417

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) 12/31/2012	Year/Period of Report 2012/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 2012.

Name of Respondent
Otter Tail Power Company

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

Date of Report
(Mo, Da, Yr)
12/31/2012

Year/Period of Report
End of 2012/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	105,904
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	27,407
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	102,853
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < \$5,000	23,699
6	Director Fees and Expenses	228,182
7	Miscellaneous Labor not provided for elsewhere	192,135
8	News Release Distribution - Sundog Interactive, Inc.	13,655
9		
10		
11		
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45		
46	TOTAL	693,835

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of acquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).

2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.

3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.

Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.

In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.

For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.

4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			766,499		766,499
2	Steam Production Plant	9,922,108	9,541			9,931,649
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	231,905				231,905
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	11,468,780	46,768			11,515,548
7	Transmission Plant	4,738,298				4,738,298
8	Distribution Plant	10,631,154				10,631,154
9	Regional Transmission and Market Operation					
10	General Plant	2,729,901				2,729,901
11	Common Plant-Electric					
12	TOTAL	39,722,146	56,309	766,499		40,544,954

B. Basis for Amortization Charges

The \$766,499 is amortization of:

Franchises and Consents (302)
\$41,840 for hydro plant licenses with a remaining life of 9.92 years at a 3.21% rate.

Miscellaneous Intangible Plan (303)
\$724,659 for computer software with a 5-year service life at a 20% rate.

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Steam Production-						
13	Big Stone Plant						
14	311	4,807		-9.10	2.00	SQ	15.18
15	312	35,434		-9.10	3.51	SQ	15.18
16	314	11,538		-9.10	3.42	SQ	15.19
17	315	2,925		-9.10	2.63	SQ	15.18
18	316	1,009		-8.90	3.17	SQ	15.19
19							
20	Steam Production						
21	Hoot Lake Plant						
22	311 - Units 2,3	744		-11.20	2.26	SQ	10.35
23	312 - Units 2,3	12,917		-11.20	4.66	SQ	10.36
24	314 - Units 2,3	1,622		-11.20	2.55	SQ	10.35
25	315 - Units 2,3	117		-11.20	1.56	SQ	10.35
26	316 - Units 2,3	506		-11.10	5.41	SQ	10.36
27							
28	Steam Production						
29	Coyote Plant						
30	311	9,929		-4.90	1.82	SQ	19.94
31	312	33,265		-4.90	2.10	SQ	19.94
32	314	9,678		-4.90	2.57	SQ	19.95
33	315	4,650		-4.90	2.31	SQ	19.95
34	316	949		-4.60	2.80	SQ	19.95
35	STEAM PRODUCTION						
36	SUBTOTAL	130,090					
37							
38	Hydro Production -						
39	Hoot Lake Hydro						
40	331	2			0.24	SQ	10.34
41	332	5			0.18	SQ	10.34
42	333	16			1.45	SQ	10.35
43	334	7			1.99	SQ	10.35
44	Hydro Production -						
45	Wright Hydro						
46	331	6			3.01	SQ	10.35
47	332	191			4.81	SQ	10.36
48	333	116			4.90	SQ	10.36
49	334	107			5.16	SQ	10.36
50	335	16			2.87	SQ	10.35

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12							
13	Hydro Production -						
14	Pisgah Hydro						
15	331	3			2.40	SQ	10.35
16	332	231			6.96	SQ	10.35
17	333	110			6.68	SQ	10.36
18	334	59			5.11	SQ	10.36
19	335	7			3.14	SQ	10.36
20							
21	Hydro Production -						
22	Dayton Hollow Hydro						
23	331				2.46	SQ	10.35
24	332	376			5.93	SQ	10.36
25	333	163			6.71	SQ	10.36
26	334	84			4.34	SQ	10.36
27	335	3			3.54	SQ	10.36
28							
29	Hydro Production -						
30	Taplin Gorge Hydro						
31	331	3			0.92	SQ	10.34
32	332	74			1.96	SQ	10.35
33	333	1			0.79	SQ	10.33
34	334	24			4.01	SQ	10.36
35	335	23			3.52	SQ	10.36
36							
37	Hydro Production -						
38	Bemidji Hydro						
39	331	162			7.82	SQ	10.36
40	332	285			6.17	SQ	10.36
41	333	170			5.05	SQ	10.36
42	334	2			2.61	SQ	10.34
43	335	1			9.71	SQ	10.36
44	HYDRO PRODUCTION						
45	SUBTOTAL	2,247					
46							
47							
48							
49							
50							

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Other Production -						
13	Jamestown Peaking #1						
14	341	52		-0.60	2.23	SQ	10.35
15	342	49		-0.60	2.27	SQ	10.35
16	343	788		-0.60	2.70	SQ	10.35
17	345	4		-0.60	1.64	SQ	10.35
18	346	37		-0.60	4.80	SQ	10.36
19	Other Production -						
20	Lake Preston Peaking						
21	341	31		-0.90	1.61	SQ	10.35
22	342	122		-0.90	3.67	SQ	10.35
23	343	588		-0.90	1.88	SQ	10.35
24	345	58		-0.90	1.61	SQ	10.35
25	346	3		-0.90	1.62	SQ	10.35
26	Other Production -						
27	Jamestown Peaking #2						
28	341	5		-0.60	3.52	SQ	10.36
29	342	10		-0.60	2.76	SQ	10.35
30	343	776		-0.60	2.03	SQ	10.35
31	345	11		-0.60	2.69	SQ	10.36
32	346	6		-0.60	2.05	SQ	10.35
33	Other Production -						
34	Fergus Falls Control Cr						
35	343	324			2.88	SQ	19.01
36	Other Production -						
37	Solway Combustion Turb						
38	341	3,162		-0.10	2.82	SQ	26.54
39	342	753		-0.10	2.83	SQ	26.54
40	343	15,722		-0.10	2.81	SQ	26.54
41	345	929		-0.10	2.80	SQ	26.54
42	346	240		-0.10	2.91	SQ	26.54
43	OTHER PRODUCTION						
44	Langdon Wind Energy						
45	341	2,095			3.92	S5	21.50
46	344	58,443			3.95	S5	21.50
47	345	5,914			3.94	S5	21.50
48	Ashtabula Wind Energy						
49	341	2,855			3.91	S5	22.50
50	344	93,347			3.90	S5	22.50

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	345	5,468			3.91	S5	22.50
13	Luverne Wind Energy						
14	341	2,063			3.87	S5	23.50
15	344	59,224			3.87	S5	23.50
16	345	4,415			3.87	S5	23.50
17	OTHER PRODUCTION						
18	SUBTOTAL	257,494					
19	Transmission Plant						
20	353	49,542	45.00	-5.00	1.61	R0.5	49.54
21	354	2,337	55.00	-10.00	1.50	R5	39.89
22	355	45,299	55.00	-50.00	2.21	S1.5	46.81
23	356	40,909	55.00	-30.00	2.04	S1.5	42.18
24	358	12	40.00	-5.00	2.99	S4	6.92
25	SUBTOTAL	138,099					
26	Distribution Plant -						
27	362	46,888	35.00	5.00	2.40	S-.5	28.38
28	364	29,041	60.00	-75.00	2.62	R3	46.33
29	365	11,155	58.00	-100.00	3.18	R3	39.22
30	367	32,949	35.00	-5.00	2.86	R4	20.59
31	368	60,701	40.00	50.00	1.46	R0.5	24.16
32	369	-963	48.00	-150.00	4.77	S5	29.73
33	369.1	20,501	40.00	-20.00	2.58	R4	31.46
34	370	13,825	33.00		2.90	S0.5	21.97
35	370.1	4,906	20.00		5.84	L3	9.44
36	370.2	222	5.00		20.00	SQ - Amortized	2.50
37	371.2	2,997	19.00	10.00	3.98	L0	16.25
38	373	2,303	16.00	-5.00	5.51	L2	9.96
39	SUBTOTAL	224,525					
40							
41	General Plant -						
42	390	14,778	45.00	10.00	1.84	L1	36.49
43	390.1	3,377		-5.00	3.51	SQ	19.00
44	390.2	343		-5.00	3.41	SQ	14.22
45	390.3	2,000		-5.00	2.37	SQ	23.69
46	391	666	15.00		6.67	SQ - Amortized	5.21
47	391.1	478	10.00		10.00	SQ - Amortized	5.05
48	391.2	282	10.00		10.00	SQ - Amortized	3.12
49	391.5	2,192	5.00		20.00	SQ - Amortized	2.70
50	391.6	744	5.00		20.00	SQ - Amortized	2.51

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	392	13,145					
13	Aircraft		7.00	39.00			
14	Autos		5.00	15.00			
15	Light Trucks		10.00	10.00			
16	Heavy Trucks & Semi		10.00	15.00			
17	Tractors (Includes		10.00	15.00			
18	Cranes)						
19	Trailers		15.00	10.00			
20	Portable Oil Purifier		10.00	20.00			
21	Trenchers		10.00	10.00			
22	Misc. Light Equip.		10.00	10.00			
23	Misc. Heavy Equip.		15.00	15.00			
24	394	1,967	15.00		6.67	SQ - Amortized	8.59
25	394.2	408	15.00		6.67	SQ - Amortized	6.43
26	395		15.00		6.67	SQ - Amortized	1.00
27	396	385	15.00	5.00	3.59	L0	16.73
28	397	434	15.00		6.67	SQ - Amortized	8.63
29	397.1	963	10.00		10.00	SQ - Amortized	3.72
30	397.2	1,750	15.00		6.67	SQ - Amortized	8.16
31	397.3	55	10.00		10.00	SQ - Amortized	4.39
32	397.4	1,038	25.00	5.00	3.88	R4	14.53
33	SUBTOTAL	45,005					
34	TOTAL	797,460					
35							
36	SUBACCOUNTS USED						
37							
38							
39							
40							
41							
42							
43							
44							
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48							
49							
50							

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2012	Year/Period of Report 2012/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

Schedule Page: 336.4 Line No.: 36 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.

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Regulatory Agency Assessments:				
2	MN Dept. of Commerce/Public Util. Commission	188,939		188,939	
3					
4	SD Public Utilities Commission	120,437		120,437	
5					
6	ND Public Service Commission	10,750		10,750	
7					
8	Federal Energy Regulatory Commission	282,642		282,642	
9					
10	Other Expenses:				
11	MN Public Utilities Commission:				
12	MN Rate Case (E017/GR-10-239) Amort 3 yrs				701,372
13	Resource Plan (E017/RP-10-623)		111,500	111,500	
14	Miscellaneous		39,595	39,595	
15					
16	ND Public Service Commission:				
17	ND Rate Case (PU 08-862) Amort 3 yrs				152,775
18	Miscellaneous		2,701	2,701	
19					
20	SD Public Utilities Commission:				
21	SD Rate Case (EL-10-011) Amort 3 yrs				151,717
22					
23	FERC				
24	Miscellaneous		99,239	99,239	
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	602,768	253,035	855,803	1,005,864

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	188,939					2
							3
Electric	928	120,437					4
							5
Electric	928	10,750					6
							7
Electric	928	282,642					8
							9
							10
							11
Electric	928						12
Electric	928	111,500			495,092	206,280	13
Electric	928	39,595					14
							15
							16
Electric	928				152,775		17
Electric	928	2,701					18
							19
							20
Electric	928				72,828	78,889	21
							22
							23
Electric	928	99,239					24
							25
							26
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							29
							30
							31
							32
							33
							34
							35
							36
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							45
		855,803			720,695	285,169	46

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

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

Classifications:

- | | |
|---|--|
| <p>A. Electric R, D & D Performed Internally:</p> <p>(1) Generation</p> <ul style="list-style-type: none"> a. hydroelectric <ul style="list-style-type: none"> 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 <p>(2) Transmission</p> | <p>a. Overhead</p> <p>b. Underground</p> <p>(3) Distribution</p> <p>(4) Regional Transmission and Market Operation</p> <p>(5) Environment (other than equipment)</p> <p>(6) Other (Classify and include items in excess of \$50,000.)</p> <p>(7) Total Cost Incurred</p> <p>B. Electric, R, D & D Performed Externally:</p> <p>(1) Research Support to the electrical Research Council or the Electric Power Research Institute</p> |
|---|--|

Line No.	Classification (a)	Description (b)
1	Electric Utility R&D	
2		
3	PERFORMED INTERNALLY:	
4	Generation	Steam - Miscellaneous
5	Other	Miscellaneous
6	Other	Miscellaneous
7		
8	Sub-Total Performed Internally	
9		
10	PERFORMED EXTERNALLY:	
11		Chartwell Inc
12		L. E. Peabody/RTC Model
13		Edison Electric Institute
14		E Source Inc
15		3 Minor Miscellaneous Projects
16		
17	Sub-Total Performed Externally	
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34	SUM OF ABOVE	
35		
36		
37		
38		

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

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

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

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

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

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

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
					1
					2
					3
31		506	31		4
18,581		920	18,581		5
10,871		930.2	10,871		6
					7
29,483			29,483		8
					9
					10
	7,377	930.2	7,377		11
	-24,255	501	-24,255		12
	-36,559	506	-36,559		13
	13,044	930.2	13,044		14
	1,290	930.2	1,290		15
					16
	-39,103		-39,103		17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
29,483	-39,103		-9,620		34
					35
					36
					37
					38

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminating and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	67,950,864		67,950,864
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	12,916,058		12,916,058
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	12,916,058		12,916,058
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,084,561		1,084,561
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,084,561		1,084,561
77	Other Accounts (Specify, provide details in footnote):			
78	Fuel Stock (151)	62,325		62,325
79	Miscellaneous Deferred Debits (186)	1,370,387		1,370,387
80	Other Electric Revenue (456)	925,211		925,211
81	Expenses of Nonutility Operations (417.1)	755,211		755,211
82	Exp for Certain Civic, Political and Related Activity (426.4)	89,488		89,488
83	Other Deductions (426.5)	170,610		170,610
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	3,373,232		3,373,232
96	TOTAL SALARIES AND WAGES	85,324,715		85,324,715

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) 12/31/2012	Year/Period of Report 2012/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) 12/31/2012	Year/Period of Report End of <u>2012/Q4</u>
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COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Not applicable.

Name of Respondent
Otter Tail Power Company

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

Date of Report
(Mo, Da, Yr)
12/31/2012

Year/Period of Report
End of 2012/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

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

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8	Not available.				
9					
10					
11					
12					
13					
14					
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37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

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		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
		Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch		\$/MW-Hr		14,248,281	\$/MW-Hr	1,776,222
2	Reactive Supply and Voltage		\$/MW-Hr		4,238,277	\$/MW-Hr	633,674
3	Regulation and Frequency Response	36,912	\$/MW-Hr	26,208		\$/MW-Hr	
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)	36,912		26,208	18,486,558		2,409,896

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) 12/31/2012	Year/Period of Report 2012/Q4
FOOTNOTE DATA			

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

Line 1, Scheduling, System Control and Dispatch does not include \$16,730 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) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
12/31/2012

Year/Period of Report
End of 2012/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	823	19	800	822	1				
2	February	779	10	900	778	1				
3	March	665	9	800	664	1				
4	Total for Quarter 1	2,267			2,264	3				
5	April	575	16	1000	574	1				
6	May	538	18	1600	537	1				
7	June	593	28	1600	592	1				
8	Total for Quarter 2	1,706			1,703	3				
9	July	682	2	1400	681	1				
10	August	653	29	1700	652	1				
11	September	587	4	1600	586	1				
12	Total for Quarter 3	1,922			1,919	3				
13	October	585	29	800	584	1				
14	November	709	26	900	708	1				
15	December	715	10	800	714	1				
16	Total for Quarter 4	2,009			2,006	3				
17	Total Year to Date/Year	7,904			7,892	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) 12/31/2012	Year/Period of Report 2012/Q4
FOOTNOTE DATA			

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

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

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

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

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

- (1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
- (2) Report on Column (b) by month the transmission system's peak load.
- (3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
- (4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
- (5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM: Not applicable

Line No.	Month	Monthly Peak MW - Total	Day of Monthly Peak	Hour of Monthly Peak	Imports into ISO/RTO	Exports from ISO/RTO	Through and Out Service	Network Service Usage	Point-to-Point Service Usage	Total Usage
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent
Otter Tail Power Company

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

Date of Report
(Mo, Da, Yr)
12/31/2012

Year/Period of Report
End of 2012/Q4

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	4,240,789
3	Steam	2,876,647	23	Requirements Sales for Resale (See instruction 4, page 311.)	3,216
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,131,943
5	Hydro-Conventional	16,990	25	Energy Furnished Without Charge	7
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	11,931
7	Other	529,034	27	Total Energy Losses	420,101
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	6,807,987
9	Net Generation (Enter Total of lines 3 through 8)	3,422,671			
10	Purchases	3,340,134			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	277,001			
17	Delivered	231,819			
18	Net Transmission for Other (Line 16 minus line 17)	45,182			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	6,807,987			

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) 12/31/2012	Year/Period of Report End of <u>2012/Q4</u>
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MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirements Sales for Resale & Associated Losses (c)	MONTHLY PEAK		
				Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	701,927	229,580	823	19	800
30	February	622,137	174,649	779	10	900
31	March	441,008	80,280	665	9	800
32	April	497,826	156,312	575	16	1000
33	May	602,045	249,931	538	18	1600
34	June	590,463	248,689	593	28	1600
35	July	587,410	195,503	682	2	1400
36	August	598,729	238,703	653	29	1700
37	September	477,233	163,918	587	4	1600
38	October	572,349	161,758	585	29	800
39	November	492,005	121,047	709	26	900
40	December	624,855	111,573	715	10	800
41	TOTAL	6,807,987	2,131,943			

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) 12/31/2012	Year/Period of Report 2012/Q4
FOOTNOTE DATA			

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

Includes interchange transactions and losses thereon.

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

Includes interchange transactions and losses thereon.

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

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

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a 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)			
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Steam		Steam			
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional		Conventional			
3	Year Originally Constructed	1981		1975			
4	Year Last Unit was Installed	1981		1975			
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	144.90		223.15			
6	Net Peak Demand on Plant - MW (60 minutes)	150		256			
7	Plant Hours Connected to Load	8187		6294			
8	Net Continuous Plant Capability (Megawatts)	149		257			
9	When Not Limited by Condenser Water	149		257			
10	When Limited by Condenser Water	149		257			
11	Average Number of Employees	80		70			
12	Net Generation, Exclusive of Plant Use - KWh	782358153		1438348932			
13	Cost of Plant: Land and Land Rights	718662		374603			
14	Structures and Improvements	32994866		22725586			
15	Equipment Costs	126801770		116470151			
16	Asset Retirement Costs	101890		62122			
17	Total Cost	160617188		139632462			
18	Cost per KW of Installed Capacity (line 17/5) Including	1108.4692		625.7336			
19	Production Expenses: Oper, Supv, & Engr	627090		604088			
20	Fuel	13048344		35454360			
21	Coolants and Water (Nuclear Plants Only)	0		0			
22	Steam Expenses	1388838		607360			
23	Steam From Other Sources	0		0			
24	Steam Transferred (Cr)	0		0			
25	Electric Expenses	662992		839101			
26	Misc Steam (or Nuclear) Power Expenses	474832		2033605			
27	Rents	1500		0			
28	Allowances	0		0			
29	Maintenance Supervision and Engineering	268542		359228			
30	Maintenance of Structures	187770		292141			
31	Maintenance of Boiler (or reactor) Plant	2759776		2401559			
32	Maintenance of Electric Plant	853512		417906			
33	Maintenance of Misc Steam (or Nuclear) Plant	407925		314937			
34	Total Production Expenses	20681121		43324285			
35	Expenses per Net KWh	0.0264		0.0301			
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	624094	2001	925120	6357	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	7012	140000	8262	140000	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	20.051	136.500	35.226	124.152	0.000	0.000
41	Average Cost of Fuel per Unit Burned	19.962	136.206	35.315	138.558	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	1.423	23.164	2.137	23.564	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.017	0.000	0.025	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	11235.000	0.000	10801.000	0.000	0.000	0.000

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

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a 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)	45	0
7	Plant Hours Connected to Load	2064	0
8	Net Continuous Plant Capability (Megawatts)	42	0
9	When Not Limited by Condenser Water	42	0
10	When Limited by Condenser Water	42	0
11	Average Number of Employees	2	0
12	Net Generation, Exclusive of Plant Use - KWh	53965370	0
13	Cost of Plant: Land and Land Rights	89809	0
14	Structures and Improvements	4251853	0
15	Equipment Costs	23788550	0
16	Asset Retirement Costs	0	0
17	Total Cost	28130212	0
18	Cost per KW of Installed Capacity (line 17/5) Including	632.1396	0
19	Production Expenses: Oper, Supv, & Engr	0	0
20	Fuel	1821098	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	599192	0
26	Misc Steam (or Nuclear) Power Expenses	68121	0
27	Rents	9567	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	7461	0
30	Maintenance of Structures	36979	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	306675	0
33	Maintenance of Misc Steam (or Nuclear) Plant	14115	0
34	Total Production Expenses	2863208	0
35	Expenses per Net KWh	0.0531	0.0000
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Natural Gas	Oil
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MMBTU	Barrels
38	Quantity (Units) of Fuel Burned	614320	1
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	618300	140000
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	2.973	0.000
41	Average Cost of Fuel per Unit Burned	2.961	83.538
42	Average Cost of Fuel Burned per Million BTU	2.961	14.207
43	Average Cost of Fuel Burned per KWh Net Gen	0.034	0.000
44	Average BTU per KWh Net Generation	11384.000	0.000

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

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

Plant Name: <i>Hoot Lake</i> (d)			Plant Name: <i>Jamestown</i> (e)			Plant Name: <i>Lake Preston</i> (f)			Line No.
	Steam			Gas Turbine			Gas Turbine		1
	Conventional			Conventional			Conventional		2
	1959			1976			1978		3
	1964			1978			1978		4
	128.50			48.11			24.10		5
	144			40			17		6
	15087			123			36		7
	142			42			20		8
	142			42			20		9
	142			42			20		10
	40			1			1		11
	655939400			1369374			279962		12
	617367			24614			12339		13
	6116976			265171			205567		14
	49150382			7457401			3891658		15
	130498			0			0		16
	56015223			7747186			4109564		17
	435.9161			161.0307			170.5213		18
	468153			0			0		19
	17624407			599192			116694		20
	0			0			0		21
	932928			0			0		22
	0			0			0		23
	0			0			0		24
	1084320			87732			13220		25
	1249955			901			809		26
	0			200			0		27
	0			0			0		28
	193102			7898			2374		29
	241466			28535			22		30
	1501684			0			0		31
	119670			133783			66167		32
	386117			1656			0		33
	23801802			859897			199286		34
	0.0363			0.6279			0.7118		35
Coal	Oil		Oil			Oil			36
Tons	Barrels		Barrels			Barrels			37
408586	1016	0	4796	0	0	1125	0	0	38
9269	140000	0	140000	0	0	140000	0	0	39
42.314	138.432	0.000	137.802	0.000	0.000	136.500	0.000	0.000	40
42.408	136.878	0.000	124.932	0.000	0.000	103.740	0.000	0.000	41
2.288	23.279	0.000	21.247	0.000	0.000	17.643	0.000	0.000	42
0.027	0.000	0.000	0.438	0.000	0.000	0.417	0.000	0.000	43
11555.000	0.000	0.000	20594.000	0.000	0.000	23626.000	0.000	0.000	44

Name of Respondent
Otter Tail Power Company

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

Date of Report
(Mo, Da, Yr)
12/31/2012

Year/Period of Report
End of 2012/Q4

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

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

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35
			36
			37
0	0	0	38
0	0	0	39
0.000	0.000	0.000	40
0.000	0.000	0.000	41
0.000	0.000	0.000	42
0.000	0.000	0.000	43
0.000	0.000	0.000	44

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2012	Year/Period of Report 2012/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

Schedule Page: 402 Line No.: 11 Column: f

Lake Preston has one part-time employee.

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

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

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End of 2012/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

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

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

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

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

FERC Licensed Project No. Plant Name: (c)	0	FERC Licensed Project No. Plant Name: (d)	0	FERC Licensed Project No. Plant Name: (e)	0	Line No.
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
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						35
						36
						37
						38

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Hydro:					
2	Hoot Lake	1914	1.00	0.8	2,585	661,278
3	Wright	1922	0.40	0.5	1,546	949,467
4	Pisgah	1917	0.52	0.7	3,497	676,950
5	Dayton Hollow	1909	0.97	1.3	6,055	1,389,596
6	Taplin Gorge	1925	0.56	0.5	3,122	966,027
7	Bemidji	1941	0.74	0.7	186	1,207,736
8						
9	Internal Combustion:					
10	Fergus Falls Control Center	1995	1.83	1.7	23	591,638
11	Diesel Generators		2.26	1.6		
12						
13	Wind Turbine Plants					
14	Langdon	2007	40.50	40.3	143,498	78,851,118
15	Ashtabula	2008	48.00	48.2	154,884	116,314,505
16	Luverne	2009	49.50	49.8	175,014	72,671,099
17						
18						
19						
20						
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46						

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
861,039	17,126		39,319 -			2
1,898,935	17,075		36,182 -			3
909,879	18,817		27,647 -			4
1,068,920	22,209		68,649 -			5
1,766,046	19,519		65,054 -			6
1,725,337	55,553		59,985 -			7
						8
						9
352,165	6,459		13,530	Oil		10
				Oil		11
						12
						13
1,956,603	852,319		14,150			14
2,413,164	696,296		14,262			15
1,459,259	1,261,524		16,043			16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
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						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) 12/31/2012	Year/Period of Report 2012/Q4
FOOTNOTE DATA			

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

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Center	Maple River	345.00	345.00	Alum Tower	48.00		1
2	Monticello	Quarry Sub	345.00	345.00	Steel Pole	29.00		1
3								
4	Fergus Falls	Inman	230.00	230.00	Wood H	19.00		1
5	Fergus Falls	Wahpeton	230.00	230.00	Wood H	29.00		1
6	Wahpeton	Hankinson	230.00	230.00	Wood H	26.00		1
7	Hankinson	Forman	230.00	230.00	Wood H	37.00		1
8	Forman	Ellendale	230.00	230.00	Wood H	47.00		1
9	Audubon (W 1/10)	Badoura	230.00	230.00	Wood H	6.00		1
10	Audubon	Sheyenne	230.00	230.00	Wood H	42.00		1
11	Winger (E 1/3)	Wilton	230.00	230.00	Alum H	18.00		1
12	Grand Forks (M 1/3)	Winnipeg	230.00	230.00	Wood H	27.00		1
13	Big Stone (N 1/3)	Hankinson	230.00	230.00	Wood H	23.00		1
14	Big Stone (S 1/4)	Blair	230.00	230.00	Wood H	15.00		1
15	Harvey	Coal Creek	230.00	230.00	Wood H	75.00		1
16	Balta	Harvey	230.00	230.00	Wood H	22.00		1
17	Rugby	Balta	230.00	230.00	Steel H	18.00		1
18	Wilton	Cass Lake	230.00	230.00	Steel H	19.00		1
19	Cass Lake	Boswell	230.00	230.00	Steel H	51.00		1
20								
21		Total	115.00	115.00	Wood H	468.00		
22		Total	115.00	115.00	SWP	394.00		
23		Total	69.00	69.00		212.00		
24								
25								
26		Total	41.60	41.60	SWP	3,764.00		
27		Total	41.60	41.60	Underground	1.00		
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	5,390.00		18

Name of Respondent
Otter Tail Power Company

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(Mo, Da, Yr)
12/31/2012

Year/Period of Report
End of 2012/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
		5,458,744	5,458,744					1
	1,470,145	8,914,353	10,384,498					2
								3
	6,339	549,602	555,941					4
	5,935	675,257	681,192					5
		475,142	475,142					6
		765,639	765,639					7
		4,127,317	4,127,317					8
		185,155	185,155					9
		818,044	818,044					10
		1,852,883	1,852,883					11
		899,455	899,455					12
		722,275	722,275					13
		608,325	608,325					14
		10,586,713	10,586,713					15
		4,230,293	4,230,293					16
		3,389,667	3,389,667					17
	407,304	10,805,241	11,212,545					18
	158,396	4,096,384	4,254,780					19
								20
	74,783	5,993,497	6,068,280					21
	49,282	21,726,596	21,775,878					22
		7,371,254	7,371,254					23
								24
								25
	4,953	89,700,585	89,705,538					26
		72,673	72,673					27
								28
								29
								30
								31
								32
								33
				5,345,563	1,925,964	43,140	7,314,667	34
								35
	2,177,137	184,025,094	186,202,231	5,345,563	1,925,964	43,140	7,314,667	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) 12/31/2012	Year/Period of Report 2012/Q4
FOOTNOTE DATA			

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

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under-ground construction and show each transmission line separately. If actual costs of completed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles (c)	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)		Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	Angus Rural	Argyle	0.50	Single pole	22.00	1	1
2	Belcourt West	Rolette	2.40	Single pole	20.00	1	1
3	Pickert 230 Substation	Binford Jesse	1.00	Single pole	21.00	1	1
4	Oakes North	Verona	1.00	Single pole	21.00	1	1
5	Dakota Valley Jud	Dakota Valley Gackle	0.30	Single pole	21.00	1	1
6	Herman	Nashua	2.00	Single pole	21.00	1	1
7	Green Valley	Green Valley	2.00	Single pole	22.00	2	2
8	Nunda	Rutland	1.00	Single pole	21.00	1	1
9	Milbank NW Substation	Milbank	0.80	Single pole	22.00	1	2
10	Cyrus City	Cyrus	0.80	Single pole	22.00	1	2
11	Cass Lake (OTP owned)	Nary Jct	8.00	H-frame	8.00	1	1
12	Forman	Ellendale	0.40	H-frame	6.00	1	1
13	Wilton	Cass Lake	19.30	H-frame	8.00	1	1
14	Cass Lake	Boswell	50.90	H-frame	8.00	1	1
15							
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40							
41							
42							
43							
44	TOTAL		90.40		243.00	15	17

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)		
266	ACSR	3102	41		48,974	21,186	3,531	73,691	1	
266	ACSR	3102	69		214,680	86,789	14,388	315,857	2	
30R	ACSR	3102	41	3,816	64,636	85,680	10,872	165,004	3	
10RT2	ACSR	3102	41	18,630	60,390	67,968	8,072	155,060	4	
10RT2	ACSR	3102	41	11,577	55,654	26,366	-83,395	10,202	5	
30R	ACSR	3102	41		139,625	82,958	26,024	248,607	6	
10RT2	ACSR	3102	41		50,266	52,553	15,401	118,220	7	
10RT2	ACSR	3102	41	23,675	892	76,443	11,274	112,284	8	
10RT2	ACSR	3102	41	13,956	112,877	92,368	7,584	226,785	9	
10RT2	ACSR	3102	41	5,955	26,516	68,184	7,275	107,930	10	
795	ACSS	HS	115		118,425	1,197,404		1,315,829	11	
795	ACSR	Horiz 19'6"	230		159,666	199,597	9,280	368,543	12	
795	ACSS	H	230	158,396	2,889,065	1,207,319		4,254,780	13	
795	ACSS	H	230	407,304	7,260,634	3,184,607		10,852,545	14	
									15	
									16	
									17	
									18	
									19	
									20	
									21	
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									23	
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									35	
									36	
									37	
									38	
									39	
									40	
									41	
									42	
									43	
					643,309	11,202,300	6,449,422	30,306	18,325,337	44

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Transmission Subs 10,000 kva or Higher				
2	Bemidji, MN - 115 kv - 63246	Transmission	115.00	69.00	13.20
3	Big Stone, SD Plant - 63314	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	Ortonville, MN - 115 kv - 63216	Transmission	115.00	41.60	
29	Pelican Rapids, MN - 115 k - 63234	Transmission	115.00	41.60	
30	Plummer, MN - 115kv - 7967	Transmission	115.00	41.60	
31	Rugby, ND - 230 kv - 63373	Transmission	230.00	115.00	13.80
32	Spiritwood, ND	Transmission	115.00	41.60	
33	Toronto, SD - 115 kv - 63210	Transmission	115.00	41.60	
34	Wahpeton Inventory (came from Cass Lake)	Transmission	115.00	69.00	41.60
35	Wahpeton Inventory (came from Forman)	Transmission	230.00	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					
39	Transmission Subtotal:		5980.00	2418.40	391.60
40					

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Transmission Subs Under 10,000 kva				
2	Colgate	Transmission	69.00	43.80	12.50
3	Green Valley	Transmission	67.00	41.60	
4	Lake Preston	Transmission	69.00	44.00	
5	St Vincent	Transmission	69.00	41.60	
6	Wahpeton Inventory (rewind from Green Valley)	Transmission	69.00	41.60	
7	Transmission Total		6323.00	2631.00	404.10
8					
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	Distribution	41.60	12.50	
14	Casselton, ND	Distribution	41.60	12.50	
15	Casselton, ND Ethanol 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 Southeast	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	

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, MN	Distribution	41.60	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:		3569.00	529.14	
15	Distribution Under 10,000 kva	Distribution			
16	Distribution Total		3569.00	529.14	
17	Transmission From Above		6323.00	2631.00	404.10
18	Transmission & Distribution		9892.00	3160.14	404.10
19					
20					
21					
22					
23					
24					
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28					
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31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
						1
19	1					2
233	1					3
45	1					4
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
33	1					27
22	1					28
13	1					29
33	1					30
125	1					31
17	1					32
45	1					33
		1				34
		1				35
140	1					36
140	1					37
						38
2811	38	2				39
						40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
						1
5	1					2
7	1					3
9	1					4
7	1					5
5		1				6
2844	42	3				7
						8
20	1					9
14	1					10
14	1					11
11	1					12
10	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
10	1					38
12	1					39
12	3					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
10	3					1
10	1					2
10	1					3
28	2					4
10	1					5
10	1					6
84	2					7
		2				8
		3				9
		1				10
24	2					11
20	2					12
12	1					13
827	58	6				14
974	1113					15
1801	1171	6				16
2844	42	3				17
4645	1213	9				18
						19
						20
						21
						22
						23
						24
						25
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						39
						40

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) 12/31/2012	Year/Period of Report 2012/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

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

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

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

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	Non-power Goods or Services Provided by Affiliated			
2	Accrued interest	Otter Tail Corporation	237	1,102,650
3	Dividends - common stock	Otter Tail Corporation	438	34,414,707
4	Corporate allocated A&G expense	Otter Tail Corporation	502	4,460
5	Corporate allocated A&G expense	Otter Tail Corporation	506	82
6	Corporate allocated A&G expense	Otter Tail Corporation	597	1,454
7	Corporate allocated A&G expense	Otter Tail Corporation	908	1,572
8	Corporate allocated A&G expense	Otter Tail Corporation	921	401,949
9	Corporate allocated A&G expense	Otter Tail Corporation	924	100
10	Corporate allocated A&G expense	Otter Tail Corporation	925	12,862
11	Corporate allocated A&G expense	Otter Tail Corporation	928	10,970
12	Corporate allocated A&G expense	Otter Tail Corporation	938	61,068
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	246,637
22	Other deductions	Otter Tail Corporation	426.5	471,080
23				
24				
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) 12/31/2012	Year/Period of Report 2012/Q4
FOOTNOTE DATA			

Schedule Page: 429 Line No.: 4 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.

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