THIS FILING IS

Item 1: [X] An Initial (Original) Submission OR [ ] Resubmission No. ____

Form 1 Approved
OMB No. 1902-0021
(Expires 2/29/2009)
Form 1-F Approved
OMB No. 1902-0029
(Expires 2/28/2009)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 2/28/2009)

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

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

Exact Legal Name of Respondent (Company)	Year/Period of Report
Otter Tail Corporation	End of 2008/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.)

Reference Schedules	Pages
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 field..."

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).

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FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Otter Tail Corporation	02 Year/Period of Report End of 2008/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*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(218) 739-8291	(1) ☒ An Original (2) ☐ A Resubmission	12/31/2008

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 / 02 Title	03 Signature	04 Date Signed *(Mo, Da, Yr)*
01 Name Kevin Moug 02 Title Chief Financial Officer	Kevin Moug	04/17/2009

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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".

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/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)
37	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	Not applicable
38	Accumulated Deferred Income Taxes-Other Property	274-275	
39	Accumulated Deferred Income Taxes-Other	276-277	
40	Other Regulatory Liabilities	278	
41	Electric Operating Revenues	300-301	
42	Sales of Electricity by Rate Schedules	304	
43	Sales for Resale	310-311	
44	Electric Operation and Maintenance Expenses	320-323	
45	Purchased Power	326-327	
46	Transmission of Electricity for Others	328-330	
47	Transmission of Electricity by ISO/RTOs	331	Not applicable
48	Transmission of Electricity by Others	332	
49	Miscellaneous General Expenses-Electric	335	
50	Depreciation and Amortization of Electric Plant	336-337	
51	Regulatory Commission Expenses	350-351	
52	Research, Development and Demonstration Activities	352-353	
53	Distribution of Salaries and Wages	354-355	
54	Common Utility Plant and Expenses	356	Not applicable
55	Amounts included in ISO/RTO Settlement Statements	397	
56	Purchase and Sale of Ancillary Services	398	
57	Monthly Transmission System Peak Load	400	
58	Monthly ISO/RTO Transmission System Peak Load	400a	Not applicable
59	Electric Energy Account	401	
60	Monthly Peaks and Output	401	
61	Steam Electric Generating Plant Statistics	402-403	
62	Hydroelectric Generating Plant Statistics	406-407	Not applicable
63	Pumped Storage Generating Plant Statistics	408-409	Not applicable
64	Generating Plant Statistics Pages	410-411	
65	Transmission Line Statistics Pages	422-423	
66	Transmission Lines Added During the Year	424-425	

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LIST OF SCHEDULES (Electric Utility) (continued)

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

Stockholders' Reports Check appropriate box:

[ ] Four copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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) [X] No

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent 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 beneficiearies for whom trust was maintained, and purpose of the trust.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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	Varistar Corporation	Holding Company	100	(7)
2				
3	Aerial Contractors, Inc.	Construction & Maintenance	100	(8)
4		Power & Communication Lines		
5				
6	BTD Manufacturing, Inc.	Metal Stamping	100	(1)
7				
8	DMI Industries, Inc.	Metal Fabrication &	100	(1)
9		Steel Flame Cutting		
10				
11	DMS Health Technologies, Inc. aka DMS	Sales & Services of Medical	100	(1)
12	Health Group	Imaging Equipment		
13				
14	DMS Imaging, Inc.	Diagnostic Medical Service	100	(2)
15				
16	DMS Leasing Corporation	Inactive	100	(2)
17				
18	Moorhead Electric, Inc.	Electrical & Utility	100	(8)
19		Contractor		
20				
21	Northern Pipe Products, Inc.	PVC Pipe Mfg.	100	(1)
22				
23	Otter Tail Energy Services Company	Energy Services	100	(7)
24				
25	E.W. Wylie Corporation	Transportation Company	100	(1)
26				
27	Vinyltech Corporation	PVC Pipe Manufacturing	100	(1)

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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1				
2	T.O. Plastics, Inc.	Plastic Products Mfg.	100	(1)
3				
4	ShoreMaster, Inc.	Waterfront Equipment Mfg.	100	(1)
5				
6	Galva Foam Marine Industries, Inc.	Waterfront Equipment Mfg.	100	(3)
7				
8	Midwest Construction Services, Inc.	Holding Company	100	(1)
9				
10	Foley Company	Mechanical & Prime Contract.	100	(1)
11				
12	Overland Mechanical Services Inc	Plumbing, Heating, Air Cond.	100	(6)
13				
14	Lynk3 Technologies, Inc	Data Servicing Group	100	(8)
15				
16	AC Equipment, Inc	Fleet Mgmt, Equip Lease &	100	(8)
17		Rental		
18				
19	Ventus Energy Systems, Inc.	Engineering & Construction	100	(8)
20		Services for Renewable Energy		
21		Industry		
22				
23	Otter Tail Assurance, LTD	Captive Insurance Company	100	(7)
24				
25	Idaho Pacific Holdings, Inc.	Holding Company	100	(1)
26				
27	Idaho Pacific Corporation	Food Ingredient Processor	100	(4)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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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.

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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				
2	Idaho Pacific Colorado Corporation	Food Ingredient Processor	100	(4)
3				
4	AWI Acquisition Company Limited	Holding Company	100	(4)
5				
6	Agra West Investments Limited	Food Ingredient Processor	100	(5)
7				
8	Shoreline Industries, Inc.	Waterfront Equipment Mfg.	100	(3)
9				
10	DMI Canada, Inc.	Metal Fabrication	100	(9)
11				
12	Aviva Sports, Inc.	Sports Product Mfg	100	(3)
13				
14	ShoreMaster Costa Rica SRL	Waterfront Equipment Mfg	100	(3)
15				
16	Green Hills Energy, LLC	Energy Services	100	(6)
17				
18	Sheridan Ridge I, LLC	Energy Services	100	(6)
19				
20	Sheridan Ridge II, LLC	Energy Services	100	(6)
21				
22	Miller Welding & Iron Works, Inc.	Metal Fabrication	100	(10)
23				
24	(1) Subsidiary of Varistar Corporation			
25	(2) Subsidiary of DMS Health Technologies, Inc			
26	(3) Subsidiary of ShoreMaster, Inc.			
27	(4) Subsidiary of Idaho Pacific Holdings, Inc.			

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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.
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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	(5) Subsidiary of AWI Acquisition			
2	Company Limited			
3	(6) Subsidiary of Otter Tail Energy Services			
4	Company			
5	(7) Subsidiary of Otter Tail Corporation			
6	(8) Subsidiary of Midwest Construction Srvcs.			
7	(9) Subsidiary of DMI Industries, Inc.			
8	(10) Subsidiary of BTD Manufacturing, Inc.			
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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 *	John D. Erickson	1,113,363
2			
3	Executive Vice President and Chief Operating Officer *	Lauris N. Molbert	937,651
4			
5	Chief Financial Officer *	Kevin G. Moug	620,155
6			
7	Corporate Secretary and General Counsel *	George Koeck	400,882
8			
9	President, Utility**	Charles S. MacFarlane	644,043
10			
11			
12			
13			
14	* Otter Tail Corporation		
15	** Otter Tail Power Company, a division of		
16	Otter Tail Corporation		
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20090420-8006 FERC PDF (Unofficial) 04/14/2009

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	John C. MacFarlane ***	
2	Chariman of the Board of Directors	Fergus Falls, Minnesota
3		
4	Karen M. Bohn ***	Edina, Minnesota
5		
6	John D. Erickson	Fergus Falls, Minnesota
7		
8	Arvid R. Liebe ***	Milbank, South Dakota
9		
10	Edward J. McIntyre	White Salmon, Washington
11		
12	Joyce Nelson Schuette	Walker, Minnesota
13		
14	Nathan I. Partain *** **	Chicago, Illinois
15		
16	Gary J. Spies	Fergus Falls, Minnesota
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18	James B. Stake	Edina, Minnesota
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20090420-8006 FERC PDF (Unofficial) 04/14/2009

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 106, 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.

1. None.

2. None.

3. None.

4. None.

5. None.

6. On July 30, 2008 the Company replaced its credit agreement with U.S. Bank National Association, which provided for a $75 million line of credit, with a new credit agreement providing for a $170 million line of credit with an accordion feature whereby the line can be increased to $250 million as described in the new credit agreement. The new credit agreement is between Otter Tail Corporation, dba Otter Tail Power Company and JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association and Merrill Lynch Bank USA, as Banks, U.S Bank National Association, as a Bank and as agent for the Banks, and Bank of America, N.A., as a Bank and as Syndication Agent. This line created an unsecured revolving credit facility the Company can draw on to support the working capital needs and other capital requirements of the Company's electric operations. Borrowings under this line of credit bear interest at LIBOR plus 0.5%, subject to adjustment based on the ratings of the Company’s senior unsecured debt. The agreement contains a number of restrictions on the business, including restrictions on its ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The agreement also contains affirmative covenants and events of default. This credit agreement is subject to renewal on July 30, 2011. As of December 31, 2008, $27.1 million was borrowed under this credit agreement.

   Minnesota Public Utilities Commission authorization given under Docket No. E-017/S-08-362 dated June 24, 2008.

   In September 2008 the Company completed a public offering of 5,175,000 common shares under its universal shelf registration statement filed with the Securities and Exchange Commission, including 675,000 common shares issued pursuant to the full exercise of the underwriters’ overallotment option. The public offering price was $30 per share. Net proceeds from the sale of the common shares after deducting underwriting discounts and commissions and offering expenses were $148.8 million. The net proceeds were used to finance the construction of Otter Tail Power Company’s 32 wind turbines and collector system at the Ashtabula Wind Center in Barnes County, North Dakota and the expansion of DMI’s wind tower manufacturing facilities in Tulsa, Oklahoma and West Fargo, North Dakota.

7. None.

8. The average annual increase for nonunion employees was 3.61% effective April 1, 2008. Wages for Local Union 1570 were increased by 4.0% effective September 1, 2008. Wages for Local Union 949, 203, 239, and 540 were increased by 3.5% effective November 1, 2008.

9. On June 10, 2008 the Sierra Club filed a complaint in the U.S. District Court for the District of South Dakota (Northern Division) against the Company and two other co-owners of Big Stone Generating Station (Big Stone). The complaint alleges certain violations of the Prevention of Significant Deterioration and New Source Performance Standards (NSPS) provisions of the Clean Air Act and certain violations of the South Dakota State Implementation Plan (South Dakota SIP). The action further alleges the defendants modified and operated Big Stone without obtaining the appropriate permits, without meeting certain emissions limits and NSPS requirements and without installing appropriate emission control technology, all allegedly in violation of the Clean Air Act and the South Dakota SIP. The Sierra Club alleges the defendants’ actions have contributed to air pollution and visibility

impairment and have increased the risk of adverse health effects and environmental damage. The Sierra Club seeks both declaratory and injunctive relief to bring the defendants into compliance with the Clean Air Act and the South Dakota SIP and to require the defendants to remedy the alleged violations. The Sierra Club also seeks unspecified civil penalties, including a beneficial mitigation project. The Company believes these claims are without merit and that Big Stone has been and is being operated in compliance with the Clean Air Act and the South Dakota SIP. The ultimate outcome of these matters cannot be determined at this time.

On August 29, 2008 Renewable Energy System Americas, Inc. (RES), a developer of wind generation and PEAK Wind Development, LLC (PEAK Wind), a group of landowners in Barnes County, North Dakota, filed a complaint with the FERC alleging that the electric utility and Minnkota Power Cooperative, Inc. (Minnkota) had acted together in violation of the Federal Power Act (FPA) to deny RES/PEAK Wind access to the Pillsbury Line, an interconnection facility which Minnkota owns to interconnect generation projects being developed by the electric utility and NextEra Energy Resources, Inc.(fka FPL Energy, Inc.) (NextEra). RES/PEAK Wind asked that (1) the FERC order Minnkota to interconnect its Glacier Ridge project to the Pillsbury Line, or in the alternative, (2) the FERC direct MISO to interconnect the Glacier Ridge project to the Pillsbury Line. RES and Peak Wind also requested that the electric utility, Minnkota and NextEra pay any costs associated with interconnecting the Glacier Ridge Project to the MISO transmission system which would result from the interconnection of the Pillsbury Line to the Minnkota transmission system, and that the FERC assess civil penalties against the electric utility. The electric utility answered the Complaint on September 29, 2008, denying the allegations of RES and PEAK Wind and requesting that the FERC dismiss the Complaint. On October 14, 2008, RES and PEAK Wind filed an Answer to the electric utility's Answer and, restated the allegations included in the initial Complaint. RES and PEAK Wind also added a request that the FERC rescind both the electric utility's waiver from the FERC Standards of Conduct and its market-based rate authority. On October 28, 2008, the electric utility filed a Reply, denying the allegations made by RES and PEAK Wind in its Answer. By Order issued on December 19, 2008, the FERC set the Complaint for hearing and established settlement procedures. The parties are engaged in settlement discussions. The Company believes the claims that the electric utility has violated the FPA are without merit. The ultimate outcome of this matter cannot be determined at this time.

10. Cascade Investment L.L.C. owns approximately 9.6% of the Company's outstanding common shares as of December 31, 2008 and is the holder of the $50 million aggregate principal amount of the Company's 5.778% senior notes due November 30, 2017.

11. (Reserved.)

12. None.

13. On April 14, 2008, the Company's Board of Directors reelected Nathan Partain and elected James Stake and John Erickson to serve three-year terms on Otter Tail Corporation's board of directors. Mr. Stake fills the vacancy created by the retirement of Dennis Emmen, former CFO of Otter Tail Power Company, who served on the board for 24 years. Mr. Stake, of Edina, Minnesota, is a recently retired 3M Company executive. He served as 3M's executive vice president of enterprise services and also chaired several 3M committees including risk management and environmental, health, and safety.

    As of December 31, 2008, Cascade Investment L.L.C. owns 3,406,499 common shares. The shares have full voting powers.

14. Not applicable.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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	1,205,646,725	1,028,917,132
3	Construction Work in Progress (107)	200-201	25,546,667	33,772,360
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		1,231,193,392	1,062,689,492
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	467,854,874	446,475,444
6	Net Utility Plant (Enter Total of line 4 less 5)		763,338,518	616,214,048
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)		763,338,518	616,214,048
15	Utility Plant Adjustments (116)	122	0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		3,869,529	3,457,886
19	(Less) Accum. Prov. for Depr. and Amort. (122)		2,124,410	1,590,324
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	382,335,879	346,183,521
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)		2,485,691	3,022,415
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		18,282,987	18,662,763
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)		404,849,676	369,736,261
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		6,431,324	4,846,287
36	Special Deposits (132-134)		1,321,533	1,376,025
37	Working Fund (135)		22,530	22,405
38	Temporary Cash Investments (136)		0	22,435,436
39	Notes Receivable (141)		50,000	0
40	Customer Accounts Receivable (142)		16,950,364	15,920,538
41	Other Accounts Receivable (143)		30,664,358	7,805,379
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		734,628	623,602
43	Notes Receivable from Associated Companies (145)		35,450,210	27,545,560
44	Accounts Receivable from Assoc. Companies (146)		411,562	1,450,489
45	Fuel Stock (151)	227	7,613,394	8,798,580
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	15,401,553	13,775,037
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		1,203,603	1,150,786
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)		24,030,090	32,501,444
62	Miscellaneous Current and Accrued Assets (174)		353,863	8,403
63	Derivative Instrument Assets (175)		404,961	5,210,365
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		139,574,717	142,223,132
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		3,044,662	2,582,350
70	Extraordinary Property Losses (182.1)	230	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
72	Other Regulatory Assets (182.3)	232	82,043,464	38,211,758
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)		-2,237	-12,671
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	342,508	625,378
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)		3,357,462	3,745,436
82	Accumulated Deferred Income Taxes (190)	234	83,821,092	54,551,854
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		172,606,951	99,704,105
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		1,480,369,862	1,227,877,546

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Otter Tail Corporation	(1) [x] An Original (2) [ ] A Rresubmission	12/31/2008	end of 2008/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	176,923,100	149,248,945
3	Preferred Stock Issued (204)	250-251	15,500,000	15,500,000
4	Capital Stock Subscribed (202, 205)	252	0	0
5	Stock Liability for Conversion (203, 206)	252	0	0
6	Premium on Capital Stock (207)	252	241,088,430	105,047,383
7	Other Paid-In Capital (208-211)	253	10,482,866	7,260,820
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)	254	9,840,795	3,422,797
11	Retained Earnings (215, 215.1, 216)	118-119	98,652,349	107,142,538
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	161,711,312	156,189,175
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)	-2,999,682	1,180,702
16	Total Proprietary Capital (lines 2 through 15)		691,517,580	538,146,766
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	331,190,000	331,290,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	4,657,140	6,985,712
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)		335,847,140	338,275,712
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)		956,000	763,829
29	Accumulated Provision for Pensions and Benefits (228.3)		129,390,297	86,674,951
30	Accumulated Miscellaneous Operating Provisions (228.4)		1,381,594	1,364,150
31	Accumulated Provision for Rate Refunds (229)		0	805,000
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)		3,297,729	2,447,170
35	Total Other Noncurrent Liabilities (lines 26 through 34)		135,025,620	92,055,100
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		27,064,471	0
38	Accounts Payable (232)		41,895,134	73,577,723
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		3,444,094	2,676,086
41	Customer Deposits (235)		700,250	770,506
42	Taxes Accrued (236)	262-263	9,331,745	11,770,897
43	Interest Accrued (237)		4,915,854	3,819,213
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Rresubmission	12/31/2008	end of 2008/Q4

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)		1,034,288	917,239
48	Miscellaneous Current and Accrued Liabilities (242)		4,073,091	771,378
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		1,690,283	5,077,975
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)		94,149,210	99,381,017
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	34,287,700	16,761,505
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	348,770	171,439
60	Other Regulatory Liabilities (254)	278	18,006,714	17,235,022
61	Unamortized Gain on Reaquired Debt (257)		0	89
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		167,388,250	123,057,760
64	Accum. Deferred Income Taxes-Other (283)		3,798,878	2,793,136
65	Total Deferred Credits (lines 56 through 64)		223,830,312	160,018,951
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		1,480,369,862	1,227,877,546

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

STATEMENT OF INCOME

Quarterly
1. Enter in column (d) the balance for the reporting quarter and in column (e) the balance for the same three month period for the prior year.
2. Report in column (f) the quarter to date amounts for electric utility function; in column (h) the quarter to date amounts for gas utility, and in (j) the quarter to date amounts for other utility function for the current year quarter.
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 (k) the quarter to date amounts for other utility function for the prior year quarter.
4. 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 columnin 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.
8. Report data for lines 8, 10 and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.

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	324,979,144	309,903,774		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	207,800,583	209,718,390		
5	Maintenance Expenses (402)	320-323	27,944,302	25,602,021		
6	Depreciation Expense (403)	336-337	29,789,956	24,289,967		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	27,372	7,566		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	622,466	458,713		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	93,289	93,287		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		2,301,007			
13	(Less) Regulatory Credits (407.4)		3,917,514	101,239		
14	Taxes Other Than Income Taxes (408.1)	262-263	8,947,060	9,411,607		
15	Income Taxes - Federal (409.1)	262-263	-23,679,888	8,105,663		
16	- Other (409.1)	262-263	-2,318,070	-281,547		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	55,423,957	16,209,282		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	16,974,890	12,741,922		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,691,710	-1,168,484		
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)		106,952	129,650		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		126,674	88,097		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		284,387,642	279,561,751		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		40,591,502	30,342,023		

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	
						1
324,979,144	309,903,774					2
						3
207,800,583	209,718,390					4
27,944,302	25,602,021					5
29,789,956	24,289,967					6
27,372	7,566					7
622,466	458,713					8
93,289	93,287					9
						10
						11
2,301,007						12
3,917,514	101,239					13
8,947,060	9,411,607					14
-23,679,888	8,105,663					15
-2,318,070	-281,547					16
55,423,957	16,209,282					17
16,974,890	12,741,922					18
-1,691,710	-1,168,484					19
						20
						21
106,952	129,650					22
						23
126,674	88,097					24
284,387,642	279,561,751					25
40,591,502	30,342,023					26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		40,591,502	30,342,023		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty 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)		10,845,228	7,202,739		
34	(Less) Expenses of Nonutility Operations (417.1)		8,928,007	6,186,959		
35	Nonoperating Rental Income (418)		43,545	41,957		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	12,993,570	33,211,381		
37	Interest and Dividend Income (419)		2,615,073	10,504,055		
38	Allowance for Other Funds Used During Construction (419.1)		2,786,095	-18,594		
39	Miscellaneous Nonoperating Income (421)		29,897,729	33,479,141		
40	Gain on Disposition of Property (421.1)			16,306		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		50,253,233	78,250,026		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		-16,095	20,090		
44	Miscellaneous Amortization (425)	340				
45	Donations (426.1)	340	527,795	557,643		
46	Life Insurance (426.2)		-140,752	-472,639		
47	Penalties (426.3)		108	365		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		117,856	216,448		
49	Other Deductions (426.5)		38,074,113	33,267,472		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		38,563,025	33,589,379		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	1,861	1,850		
53	Income Taxes-Federal (409.2)	262-263	1,970,636	2,106,068		
54	Income Taxes-Other (409.2)	262-263	-6,219,847	-2,758,318		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	2,202,238	2,400,160		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	2,144,401	1,804,978		
57	Investment Tax Credit Adj.-Net (411.5)		-673	-673		
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-4,190,186	-55,891		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		15,880,394	44,716,538		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		20,612,217	16,933,088		
63	Amort. of Debt Disc. and Expense (428)		327,444	705,244		
64	Amortization of Loss on Reaquired Debt (428.1)		387,973	327,174		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		89	118		
67	Interest on Debt to Assoc. Companies (430)	340		1,590,735		
68	Other Interest Expense (431)	340	1,712,137	3,817,390		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		1,692,397	2,275,656		
70	Net Interest Charges (Total of lines 62 thru 69)		21,347,285	21,097,857		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		35,124,611	53,960,704		
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)		35,124,611	53,960,704		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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		106,972,504	114,887,748
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	FIN 48 Cumulative Effect			(118,576)
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			(118,576)
16	Balance Transferred from Income (Account 433 less Account 418.1)		22,131,041	20,749,323
17	Appropriations of Retained Earnings (Acct. 436)			
18	Excess hydro licensing amortization		-28,575	13,619
19	Storm reserve required by First Mortgage Bond Indenture			
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-28,575	13,619
23	Dividends Declared-Preferred Stock (Account 437)			
24	$3.60 Preferred $216,000		-216,000	(216,000)
25	$4.40 Preferred $110,000		-110,000	(110,000)
26	$4.65 Preferred $139,500		-139,500	(139,500)
27	$6.75 Preferred $270,000		-270,000	(270,000)
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-735,500	(735,500)
30	Dividends Declared-Common Stock (Account 438)			
31	2008: $1.19 per share; 2007: $1.17 per share		-37,357,163	(34,780,138)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-37,357,163	(34,780,138)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		7,471,433	6,956,028
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		98,453,740	106,972,504
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39	Amortization reserve, federal (Account 215.1)		198,609	170,034
40				

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STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)		198,609	170,034
	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)		198,609	170,034
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		98,652,349	107,142,538
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		156,189,175	129,933,821
50	Equity in Earnings for Year (Credit) (Account 418.1)		12,993,570	33,211,382
51	(Less) Dividends Received (Debit)		7,471,433	6,956,028
52				
53	Balance-End of Year (Total lines 49 thru 52)		161,711,312	156,189,175

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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)	35,124,611	53,960,704
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	30,351,414	24,822,475
5	Amortization of intangible plant	622,466	458,713
6	Amortization of plant acquisition adjustments and deferred costs	93,289	93,287
7			
8	Deferred Income Taxes (Net)	16,066,994	-7,851,790
9	Investment Tax Credit Adjustment (Net)	17,526,195	8,580,844
10	Net (Increase) Decrease in Receivables	-30,643,502	45,245,512
11	Net (Increase) Decrease in Inventory	-441,330	-2,704,460
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-32,296,278	44,663,528
14	Net (Increase) Decrease in Other Regulatory Assets	-43,831,706	11,026,783
15	Net Increase (Decrease) in Other Regulatory Liabilities	771,692	11,856,067
16	(Less) Allowance for Other Funds Used During Construction	2,786,095	-18,594
17	(Less) Undistributed Earnings from Subsidiary Companies	5,522,137	26,255,353
18	Other: (Increase) decrease in noncurrent assets and deferred debits	1,183,784	-2,984,392
19	Other: Increase (decrease) in noncurrent liabilities & deferred credit	38,967,378	-12,910,306
20	Other: (Increase) decrease in other current assets	12,828,481	-11,305,318
21	Other: Losses on investments in noncurrent assets	393,126	353,301
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	38,408,382	137,068,189
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-177,657,553	-125,529,395
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-411,643	-736,921
30	(Less) Allowance for Other Funds Used During Construction	-2,786,095	18,594
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-175,283,101	-126,284,910
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	-30,630,221	-18,628,715
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)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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: Decrease in funds on deposit with trustee	54,492	222,403
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-205,858,830	-144,691,222
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		205,000,000
62	Preferred Stock		
63	Common Stock	166,937,248	11,302,873
64	Other:Amortized debt expense	-462,312	856,925
65			
66	Net Increase in Short-Term Debt (c)	27,064,471	
67	Other: Capital stock expense	-6,417,998	
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	187,121,409	217,159,798
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-2,428,572	-117,358,572
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		-38,900,000
79			
80	Dividends on Preferred Stock	-735,500	-735,500
81	Dividends on Common Stock	-37,357,163	-34,780,138
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	146,600,174	25,385,588
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-20,850,274	17,762,555
87			
88	Cash and Cash Equivalents at Beginning of Period	27,304,128	9,541,573
89			
90	Cash and Cash Equivalents at End of period	6,453,854	27,304,128

Name of Respondent Otter Tail Corporation	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4

FOOTNOTE DATA

Schedule Page: 120 Line No.: 5 Column: a
Amortization of intangible plant.

Schedule Page: 120 Line No.: 6 Column: a
Amortization of plant acquisition adjustments and deferred costs.

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 debits, 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.: 21 Column: a
Loss on affordable housing investments.

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
Change in unamortized debt expense.

Schedule Page: 120 Line No.: 67 Column: a
Expenses related to capital stock issuance, including legal costs, registration fees, underwriters fees, and offering fees.

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report 12/31/2008	Year/Period of Report End of 2008/Q4

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 Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

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

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.

	2008	2007
Cash Equivalents	$ 0	$ 22,435,436

Reconciliation	2008	2007
Cash – Account 131 (Line 35, Page 110)	$ 6,431,324	$ 4,846,287
Working Fund – Account 135 (Line 37, Page 110)	22,530	22,405
Cash Equivalent – Account 136 (Above)	0	22,435,436
	$ 6,453,854	$ 27,304,128
Supplemental Disclosure of Cash Flow Information:		
Cash Paid During the year for:		
Interest (Net of Amount Capitalized)	$ 19,581,219	$ 17,274,155
Income Taxes	$ 1,633,487	$ 8,594,658

Otter Tail Corporation
Notes to Comparative Financial Statements
For the years ended December 31, 2008 and 2007

1. Summary of Significant Accounting Policies

Principles of Consolidation
The Company has several subsidiaries. The net investment in such subsidiaries is included in Other Property and Investments and the results of subsidiaries' operations are included in Other Income and Deductions. If Generally Accepted Accounting Principles (GAAP) were followed, the respective assets and liabilities of these subsidiaries would be included in the accompanying financial statements.

Regulation and Statement of Financial Accounting Standards No. 71
As a regulated entity, the Company accounts for the financial effects of regulation in accordance with SFAS No. 71. This statement 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, the Company defers utility debt redemption premiums and amortizes such costs over the original life of the reacquired bonds. See note 3 for further discussion.

The Company's regulated electric utility business 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). These accounting policies differ in some respects from those used by the Company's nonelectric businesses.

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. This report differs from GAAP due to FERC requiring the presentation of subsidiaries on the equity method of accounting, which differs from Statement of Financial Accounting Standards No. 94, "Consolidation of All Majority-Owned Subsidiaries" (SFAS No. 94). SFAS No. 94 requires that all majority-owned subsidiaries be consolidated. The Company has several subsidiaries and the net investment in such subsidiaries is included in Other Property and Investments and the results for these subsidiaries' operations are included in Other Income and Deductions. In addition, the associated Goodwill and certain intangible assets related to these subsidiaries are excluded for FERC regulatory reporting as compared to GAAP requirements which would include the amounts. The other 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 tax asset or liability.

See note 13 for details.

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 $4,478,000 in 2008 and $2,257,000 in 2007. 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, a regulatory liability. Maintenance, repairs and replacement of minor items of property are charged to operating expenses. The provisions for utility depreciation for financial reporting purposes are made on the straight-line method based on the estimated service lives of the properties. Such provisions as a percent of the average balance of depreciable electric utility property were 2.81% in 2008 and 2.78% in 2007. 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 comparative balance sheets include the Company'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, 2008 and 2007 comparative balance sheets:

(in thousands)	2008	2007
Big Stone Plant:		
Electric Plant in Service	$ 135,623	$ 136,493
Accumulated Depreciation	(74,416)	(72,342)
Net Plant	$ 61,207	$ 64,151
Coyote Station:		
Electric Plant in Service	$ 148,109	$ 147,724
Accumulated Depreciation	(86,911)	(83,417)
Net Plant	$ 61,198	$ 64,307

The Company’s share of direct revenue and expenses of the jointly owned plants is included in operating revenue and expenses in the comparative statements of income.

Recoverability of Long-Lived Assets

The Company reviews its long-lived assets whenever events or changes in circumstances indicate the carrying amount of the assets may not be recoverable. The Company determines potential impairment by comparing the carrying value 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 values, the Company would determine whether an impairment loss should be recognized. An impairment loss would be quantified by comparing the amount by which the carrying value 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

Comprehensive interperiod income tax allocation is used for substantially all book and tax temporary differences. Deferred income taxes arise for all temporary differences between the book and tax basis of assets and liabilities. Deferred taxes are recorded using the tax rates scheduled by tax law to be in effect in the periods when the temporary differences reverse. The Company amortizes investment tax credits over the estimated lives of related property. The Company adopted Financial Accounting Standards Board (FASB) Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109,* on January 1, 2007 and has recognized, in its comparative 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 December 31, 2008. The term "more-likely-than-not" means a likelihood of more than 50%. The Company classifies interest and penalties on tax uncertainties as components of the provision for income taxes. See note 14 to the comparative financial statements regarding the Company’s accounting for uncertain tax positions.

Revenue Recognition

In the case of derivative instruments, such as the electric utility's forward energy contracts, marked-to-market and realized gains and losses are recognized on a net basis in revenue in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended and interpreted. 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.

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 accrued for fuel and purchased power costs incurred in excess of amounts recovered in base rates but not yet billed through the FCA and for renewable resource 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.

The Company'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 the Company's comparative statement of income. Under SFAS No. 133 as amended and interpreted, the Company'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. The Company 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

The Company 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, asset impairment evaluations, tax provisions, collectability of trade accounts receivable, self-insurance programs, unbilled electric 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

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

Investments

At December 31, 2008 and 2007 the Company had investments of $1,426,000 and $1,837,000, respectively, in limited partnerships that invest in tax-credit qualifying affordable housing projects. These investments provided the Company with tax credits of $55,000 in 2008 and $285,000 in 2007. The balance of investments at December 31, 2008 consists of $32,000 in additional investments accounted for under the equity method, $500,000 of additional investments accounted under the cost method and $528,000 related to participation in economic development loan pools accounted for under the cost method. The balance of investments at December 31, 2007 consists of $30,000 in additional investments accounted for under the equity method, $500,000 of additional investments accounted for under the cost method and $655,000 related to participation in economic development loan pools accounted for under the cost method. See further discussion under note 11.

Fair Value Measurements

Effective January 1, 2008, the Company adopted SFAS No. 157, *Fair Value Measurements*, for recurring fair value measurements. SFAS No. 157 provides a single definition of fair value and requires enhanced disclosures about assets and liabilities measured at fair value. SFAS No. 157 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 SFAS No. 157 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, such as the complex and subjective models and forecasts used to determine the fair value of financial transmission rights.

The following table presents, for each of these hierarchy levels, the Company’s assets and liabilities that are measured at fair value on a recurring basis as of December 31, 2008:

(in thousands)	Level 1	Level 2	Level 3	Total
Assets:				
Investments for Nonqualified Retirement Savings Retirement Plan:				
Money Market and Mutual Funds and Cash	$ 25	$ --	$ --	$ 25
Cash Surrender Value of Life Insurance Policies		8,014		8,014
Cash Surrender Value of Keyman Life Insurance Policies – Net of Policy Loans		10,244		10,244
Forward Energy Contracts		405		405
Total Assets	$ 25	$ 18,663	$ 0	$ 18,688
Liabilities:				
Forward Energy Contracts	$ --	$ 1,690	$ --	$ 1,690
Asset Retirement Obligations			3,298	3,298
Total Liabilities	$ 0	$ 1,690	$ 3,298	$ 4,988
Net Assets (Liabilities)	$ 25	$ 16,973	$ (3,298)	$ 13,700

Inventories

The Electric segment inventories are reported at average cost. Inventories consist of plant materials, fuel, and operating supplies.

New Accounting Standards

SFAS No. 157, *Fair Value Measurements,* was issued by the FASB in September 2006. SFAS No. 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. SFAS No. 157 applies under other accounting pronouncements that require or permit fair value measurements where fair value is the relevant measurement attribute. Accordingly, this statement does not require any new fair value measurements. The adoption of SFAS No. 157 on January 1, 2008 resulted in additional footnote disclosures related to the use of fair value measurements in the areas of investments, derivatives, asset retirement obligations, goodwill and asset impairment evaluations, financial instruments and acquisitions, but did not have a significant impact on the Company’s comparative balance sheet, income statement or statement of cash flows.

SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities - Including an Amendment of FASB Statement No. 115,* was issued by the FASB in February 2007. SFAS No. 159 provides companies with an option to measure, at specified election dates, many financial instruments and certain other items at fair value that are not currently measured at fair value. A company that adopts SFAS No. 159 will report unrealized gains and losses in earnings at each subsequent reporting date on items for which the fair value option has been elected. This statement also establishes presentation and disclosure requirements to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. The Company adopted SFAS No. 159 on January 1, 2008. The adoption of this pronouncement had no effect on the Company’s comparative financial statements because the Company had not opted, nor does it currently plan to opt, to apply fair value accounting to any financial instruments or other items that it is not currently required to account for at fair value.

SFAS No. 141 (revised 2007), Business Combinations (SFAS No. 141(R)), was issued by the FASB in December 2007. SFAS No. 141(R) replaces SFAS No. 141, *Business Combinations,* and will apply prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. SFAS No.

141(R) applies to all transactions or other events in which an entity (the acquirer) obtains control of one or more businesses (the acquiree). In addition to replacing the term "purchase method of accounting" with "acquisition method of accounting," SFAS No. 141(R) requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date, measured at their fair values as of that date, with limited exceptions. This guidance will replace SFAS No. 141's cost-allocation process, which requires the cost of an acquisition to be allocated to the individual assets acquired and liabilities assumed based on their estimated fair values. SFAS No. 141's guidance results in not recognizing some assets and liabilities at the acquisition date, and it also results in measuring some assets and liabilities at amounts other than their fair values at the acquisition date. For example, SFAS No. 141 requires the acquirer to include the costs incurred to effect an acquisition (acquisition-related costs) in the cost of the acquisition that is allocated to the assets acquired and the liabilities assumed. SFAS No. 141(R) requires those costs to be expensed as incurred. In addition, under SFAS No. 141, restructuring costs that the acquirer expects but is not obligated to incur are recognized as if they were a liability assumed at the acquisition date. SFAS No. 141(R) requires the acquirer to recognize those costs separately from the business combination.

SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133,* was issued by the FASB in March 2008. SFAS No. 161 requires enhanced disclosures about an entity's derivative and hedging activities to improve the transparency of financial reporting. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. Adoption of SFAS No. 161 will result in additional footnote disclosures related to the Company's use of derivative instruments but those additional disclosures will not be extensive because the derivative instruments currently held by the Company are not designated as hedging instruments under SFAS No. 161.

2. Rate and Regulatory Matters

Minnesota

General Rate Case-- In an order issued by the Minnesota Public Utilities Commission (MPUC) on August 1, 2008 the electric utility was granted an increase in Minnesota retail electric rates of $3.8 million or approximately 2.9%, compared with the originally requested increase of approximately 6.7%. An interim rate increase of 5.4% went into effect on November 30, 2007. The electric utility will refund Minnesota customers the difference between interim rates and final rates, with interest, in March 2009. Amounts refundable totaling $3.9 million have been recorded as a liability on the Company's comparative balance sheet as of December 31, 2008. The MPUC approved a rate of return on equity of 10.43% on a capital structure with 50.0% equity. The electric utility deferred recognition of $1.5 million in rate case-related filing and administrative costs in June 2008 that are subject to amortization and recovery over three years under new rates as ordered by the MPUC. As a result of an MPUC decision on reconsideration of the treatment of profit margins on the resale of electricity purchased from other companies, the electric utility will assign an amount of its costs to this unregulated activity but will not be required to credit any portion of nonasset-based margins to retail customers.

Capacity Expansion 2020 (CapX 2020) Mega Certificate of Need--On August 16, 2007 the eleven CapX 2020 utilities asked the MPUC to determine the need for three 345-kilovolt (kV) transmission lines. Evidentiary hearings for the Certificate of Need for the three CapX 2020 345-kv transmission line projects began in July 2008 and continued into August 2008. The MPUC is expected to decide if the lines meet regulatory need requirements by early 2009. The MPUC would determine routes for the new lines in separate proceedings. Portions of the lines would also require approvals by federal officials and by regulators in North Dakota, South Dakota and Wisconsin. After regulatory need is established and routing decisions are completed (expected in 2009 or 2010), construction will begin. The lines would be expected to be completed three or four years later. Great River Energy and Xcel Energy are leading these projects, and Otter Tail Power Company and eight other utilities are involved in permitting, building and financing. Otter Tail Power Company is directly involved in two of these three projects and serves as the lead utility in a fourth Group 1 project, the Bemidji-Grand Rapids 230-kv line which has an expected in-service date of 2012-2013.

The electric utility filed a Certificate of Need for the fourth project on March 17, 2008. The Department of Commerce Office of Energy Security (MNOES) staff completed briefing papers regarding the Bemidji-Grand Rapids route permit application. The MNOES staff recommended to the MPUC: (1) the route permit application be found to be complete, (2) the need determination not be sent to a contested case but be handled informally by MPUC review, and (3) the Certificate of Need and route permit proceedings be combined as requested. The MPUC met on June 26, 2008 to act on the MNOES staff recommendation. The MPUC agreed the Certificate of Need and route permit applications were complete. The commissioners asked the CapX 2020 utilities to add a section to the Certificate of Need application addressing how the new Minnesota Conservation Improvement Programs (CIP) statutes will affect the need for the project. Because no one has intervened in the Certificate of Need proceeding, the MPUC will handle the Certificate of Need application as an uncontested case. The MNOES subsequently recommended that need for the line has been established. The MPUC is expected to determine if there is a need for this line and, if appropriate, issue the route permit in spring 2010.

Renewable Energy Standards, Conservation and Renewable Resource Riders--In February 2007, the Minnesota legislature passed a renewable energy standard requiring the electric utility 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. The electric utility has acquired renewable resources and expects to acquire additional renewable resources in order to maintain compliance with the Minnesota renewable energy standard. By the end of 2010, the electric utility expects to have sufficient renewable energy resources available to comply with the required 2012 level of the Minnesota renewable energy standard. The electric utility's compliance with the Minnesota renewable energy standard will be measured through the Midwest Renewable Energy Tracking System.

Under the Next Generation Energy Act of 2007 passed by the Minnesota legislature in May 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 standards. The MPUC is now 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 now 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.

In an order issued on August 15, 2008, the MPUC approved the electric utility's proposal to implement a Renewable Resource Cost Recovery Rider for its Minnesota jurisdictional portion of investment in renewable energy facilities. The rider enables the electric utility to recover from its Minnesota retail customers its investments in owned renewable energy facilities and provides for a return on those investments. The Renewable Resource Adjustment of 0.19 cents per kilowatt-hour (kWh) was included on Minnesota customers' electric service statements beginning in September 2008. The first renewable energy project for which the electric utility will receive cost recovery is its 40.5 megawatt ownership share of the Langdon Wind Energy Center, which became fully operational in January 2008. The electric utility has recognized a regulatory asset of $3.0 million for revenues that are eligible for recovery through the rider but have not been billed to Minnesota customers as of December 31, 2008.

The electric utility is awaiting a decision from the MPUC on its 2009 Rider Adjustment filing with an expected implementation date of April 2009. The 2009 Rider Adjustment filing includes a request for recovery of the electric utility's investment costs and expenses related to its 32 wind turbines at the Ashtabula Wind Energy Center that became commercially operational in November 2008.

In addition to the Renewable Resource Cost Recovery 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 electric transmission facilities. The MPUC may approve a tariff rider to recover the Minnesota jurisdictional costs of new transmission facilities that have been previously approved by the MPUC in a Certificate of Need proceeding or certified by the MPUC as a Minnesota priority transmission project or investment and expenditures made to transmit the electricity generated from renewable generation sources ultimately used to provide service to the utility's retail customers. Such transmission cost recovery riders would allow a return on investments at the level approved in a utility's last general rate case. The electric utility expects to file a proposed rider with the MPUC to recover its share of costs of eligible transmission infrastructure upgrades projects in 2009.

Recovery of MISO Costs--In December 2005, the MPUC issued an order denying the electric utility's request to allow recovery of certain MISO-related costs through the FCA in Minnesota retail rates and requiring a refund of amounts previously collected pursuant to an interim order issued in April 2005. The electric utility recorded a $1.9 million reduction in revenue and a refund payable in December 2005 to reflect the refund obligation. On February 9, 2006 the MPUC decided to reconsider its December 2005 order. The MPUC's final order was issued on February 24, 2006 requiring jurisdictional investor-owned utilities in the state to participate with the Minnesota Department of Commerce (MNDOC) and other parties in a proceeding that would evaluate suitability of recovery of certain MISO Day 2 energy market costs through the FCA. The February 24, 2006 order eliminated the refund provision from the December 2005 order and allowed that any MISO-related costs not recovered through the FCA may be deferred for a period of 36 months, with possible recovery through base rates in the utility's next general rate case. As a result, the electric utility recognized $1.9 million in revenue and reversed the refund payable in February 2006. The Minnesota utilities and other parties submitted a final report to the MPUC in July 2006.

In an order issued on December 20, 2006 the MPUC stated that except for schedule 16 and 17 administrative costs, discussed below, each petitioning utility may recover the charges imposed by the MISO for MISO Day 2 operations (offset by revenues from Day 2 operations via net accounting) through the calculation of the utility's FCA from the period April 1, 2005 through a period of at least three years after the date of the order. The MPUC also ordered the utilities to refund schedule 16 and 17 costs collected through the FCA since the inception of MISO Day 2 Markets in April 2005 and stated that each petitioning utility may use deferred accounting for MISO schedule 16 and 17 costs incurred since April 1, 2005. This deferred accounting may continue for ongoing schedule 16 and 17 costs, without the accumulation of interest, until the earlier of March 1, 2009 or the utility's next electric rate case. Pursuant to this December 20, 2006 order, the electric utility was ordered to refund $446,000 in MISO schedule 16 and 17 costs to Minnesota retail customers through the FCA over a twelve-month period beginning in January 2007. The electric utility requested recovery of the deferred costs and recovery of the ongoing costs in its general rate case filed in October 2007 and, in January 2008, began amortizing $855,000 of deferred MISO schedule 16 and 17 costs over a 35-month period. The August 1, 2008 MPUC Order in the general rate case allowed future recovery of MISO schedule 16 and 17 costs and recovery of the deferred Schedule 16 and 17 costs.

Minnesota Annual Automatic Adjustment Report on Energy Costs (AAA Report)--The MNDOC and the electric utility identified two operational situations which are not covered in the approved method for allocating MISO costs contained in the final December 20, 2006 MPUC order discussed above. One relates to plants not expected to be available for retail but that produce energy in certain hours, resulting in wholesale sales. The other situation is related to Financial Transmission Rights (FTRs) not needed for retail load. For the period July 1, 2005 through June 30, 2007 the electric utility determined its Minnesota customers' portion of costs associated with these situations to be $765,000. The data was provided to the MNDOC during the course of the MNDOC's review of the AAA Report. The electric utility offered to refund $765,000 to its Minnesota customers to settle this and other issues raised by the MNDOC in the AAA Report docket before the MPUC and the MNDOC accepted the offer in October 2007 and recommended that the MPUC include the refund in its final order. The electric utility also agreed to modifications to the MISO Day 2 cost allocations that were resolved in the MPUC's December 20, 2006 order. The electric utility agreed to make some of those modifications retroactive back to January 1, 2007. The MPUC accepted the electric utility's refund offer and modifications and closed this docket on February 6, 2008. In December 2007, the electric utility recorded a liability and a reduction to revenue of $805,000 for the amount of the refund offer and similar revenues collected subsequent to June 30, 2007. Refunds to Minnesota customers were completed during 2008.

Claims of Improper Regulatory Filings--In September 2004, the Company provided a letter to the MPUC summarizing issues and conclusions of an internal investigation completed by the Company related to claims of allegedly improper regulatory filings brought to the attention of the Company by certain individuals. A hearing before the MPUC was held on February 28, 2006. As a result of the hearing, the electric utility agreed that within 90 days it would file a revised Regulatory Compliance Plan, an updated Corporate Cost Allocation Manual and documentation of the definitions of its chart of accounts. The electric utility filed these documents with the MPUC in the second quarter of 2006. Subsequently, at a MPUC hearing on January 25, 2007 all remaining open issues were resolved. On two of the issues resolved, the MPUC required the electric utility to include all of the Company's short-term debt in its calculations of allowance for funds used during construction (AFUDC) and the electric utility agreed to provide the MPUC the results of an ongoing FERC operational audit when available. The Company recorded a noncash charge to Other Income and Deductions of $3.3 million in 2006 related to the disallowance of a portion of capitalized AFUDC from the electric utility's rate base as a result of including all of the Company's short-term debt, regardless of use, in the electric utility's calculations of AFUDC. On December 12, 2007 the MPUC issued its order closing the investigation subject to the Company's continuing responsibility to file the report on its FERC operational audit as soon as available and subject to any further development of the record required in the electric utility's recent general rate case. FERC Order (IN08-6-000), resolving alleged network transmission service violations by the electric utility of the Open Access Transmission and Energy Markets Tariff of the MISO was issued on May 29, 2008 and filed with the MPUC on June 4, 2008.

North Dakota

General Rate Case-- On November 3, 2008 the electric utility 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, to begin on January 2, 2009, of approximately 4.1%, or $4.8 million annualized. A final decision by the North Dakota Public Service Commission (NDPSC) on the electric utility's request is expected by August 1, 2009. Interim rates will remain in effect for all North Dakota customers until the NDPSC makes a final determination on the electric utility's request. If final rates are lower than interim rates, the electric utility will refund North Dakota customers the difference with interest.

Renewable Resource Cost Recovery Rider--On May 21, 2008 the NDPSC approved the electric utility's request for a Renewable Resource Cost Recovery Rider to enable the electric utility to recover the North Dakota share of its investments in renewable energy facilities it owns in North Dakota. The Renewable Resource Cost Recovery Rider Adjustment of 0.193 cents per kWh was included on North Dakota customers' electric service statements beginning in June 2008. The first renewable energy project for which the electric utility will receive cost recovery is its 40.5 megawatt ownership share of the Langdon Wind Energy Center, which became fully operational in January 2008. The electric utility may also recover through this rider costs associated with other new renewable energy projects as they are completed. The electric utility has 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 Renewable Resource Cost Recovery Rider Adjustment. A Renewable Resource Cost Recovery Rider Adjustment rate of 0.51 cents per kWh was approved by the NDPSC on January 14, 2009 and went into effect beginning with billing statements sent on February 1, 2009.

The electric utility had not been deferring recognition of its renewable resource costs eligible for recovery under the North Dakota Renewable Resource Cost Recovery Rider but had been charging those costs to operating expense since January 2008. After approval of the rider, the electric utility accrued revenues related to its investment in renewable energy and for renewable energy costs incurred since January 2008 that are eligible for recovery through the North Dakota Renewable Resource Cost Recovery Rider. The Company's December 31, 2008 comparative balance sheet includes a regulatory asset of $2.0 million for revenues that are eligible for recovery through the North Dakota Renewable Resource Cost Recovery Rider but that had not been billed to North Dakota customers as of December 31, 2008.

North Dakota legislation also 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. However, the electric utility has requested recovery of such costs in its general rate case filed in November 2008.

Recovery of MISO Costs--In February 2005, the electric utility filed a petition with the NDPSC to seek recovery of certain MISO-related costs through the FCA. The NDPSC granted interim recovery through the FCA in April 2005, but similar to the decision of the MPUC, conditioned the relief as being subject to refund until the merits of the case are determined. In August 2007, the NDPSC approved a settlement agreement between the electric utility and an intervener representing several large industrial customers in North Dakota. Under the approved settlement agreement, the electric utility refunded $493,000 of MISO schedule 16 and 17 costs collected through the FCA from April 2005 through July 2007 to North Dakota customers beginning in October 2007 and ending in January 2008. The electric utility deferred recognition of these costs plus $330,000 in MISO schedule 16 and 17 costs incurred from August 2007 through December 2008 and requested recovery of these deferred costs in its general rate case filed in North Dakota in November 2008. As of December 31, 2008 the electric utility had deferred $823,000 in MISO schedule 16 and 17 costs in North Dakota, which it will amortize over 36 months beginning in January 2009 in conjunction with the implementation of interim rates in North Dakota. Requests for approval of base rate recovery for deferred and on-going MISO schedule 16 and 17 costs are included in the pending general rate case.

South Dakota

General Rate Case-- On October 31, 2008 the electric utility filed a general rate case in South Dakota requesting an overall revenue increase of approximately $3.8 million, or 15.3%, which provides for recovery of renewable resource investments and expenses in base rates. South Dakota rules do not provide for interim rate increases pending approval of final rates. A final decision by the SDPUC on the electric utility's request is expected in mid-summer 2009.

Federal

Revenue Sufficiency Guarantee (RSG) Charges--On April 25, 2006 the FERC issued an order requiring MISO to refund to customers, with interest, amounts related to real-time RSG charges that were not allocated to day-ahead virtual supply offers in accordance with MISO's Open Access Transmission and Energy Markets Tariff (TEMT) going back to the commencement of MISO Day 2 markets in April 2005. On May 17, 2006 the FERC issued a Notice of Extension of Time, permitting MISO to delay compliance with the directives contained in its April 2006 order, including the requirement to refund to customers the amounts due, with interest, from April 1, 2005 and the requirement to submit a compliance filing. The Notice stated that the order on rehearing would provide the appropriate guidance regarding the timing of the compliance filing. On October 26, 2006 the FERC issued an order on rehearing of the April 25, 2006 order, stating it would not require refunds related to real-time RSG charges that had not been allocated to day-ahead virtual supply offers in accordance with MISO's TEMT going back to the commencement of the MISO Day 2 market in April 2005. However, the FERC ordered prospective allocation of RSG charges to virtual transactions consistent with the TEMT to prevent future inequity and directed MISO to propose a charge that assesses RSG costs to virtual supply offers based on the RSG costs that virtual supply offers cause within 60 days of the October 26, 2006 order. On December 27, 2006 the FERC issued an order granting rehearing of the October 26, 2006 order.

On March 15, 2007 the FERC issued an order denying requests for rehearing of the RSG rehearing order dated October 26, 2006. In the March 15, 2007 order on rehearing, the FERC stated that its findings in the April 25, 2006 RSG order that virtual offers should share in the allocation of RSG costs, per the terms of the currently effective tariff, served as notice to market participants that virtual offers, for those market participants withdrawing energy, were liable for RSG charges. FERC clarified that the RSG rehearing order's waiver of refunds applies to the period before that order, from market start-up in April 2005 until April 24, 2006. After that date, virtual supply offers are liable for RSG costs and therefore, to the extent virtual supply offers were not assessed RSG costs, refunds are due for the period starting April 25, 2006.

On November 5, 2007 the FERC issued two orders related to the RSG proceeding. In the first order, the FERC accepted the MISO's April 17, 2007 RSG compliance filing to comply with the FERC's March 15, 2007 RSG order. The compliance reinserted language requiring the actual withdrawal of energy by market participants, restored the MISO's original TEMT language allocating RSG costs to virtual transactions, revised the effective date for allocation to imports, provided an explanation of its efforts to reflect partial-hour revenue determinations in its software development, and revised several definitions. The second related RSG order issued by FERC on November 5, 2007 was its order on rehearing on its April 25, 2006 order in which it rejected the MISO's proposal to remove references to virtual supply from the TEMT provisions related to calculating RSG charges (FERC Docket Nos. ER04-691-084 and ER04-691-086). In this order, the FERC denied the requests for rehearing of the RSG second rehearing order (the electric utility was one of the parties that sought rehearing) and FERC denied all requests for rehearing of the RSG compliance order.

In the RSG compliance order, the FERC rejected the MISO's proposal to allocate costs based on net virtual offers, i.e., virtual offers minus virtual bids, and clarified that the currently effective tariff, which allocates RSG costs to virtual supply offers, remains in effect. In the RSG second rehearing order, the FERC clarified that for those market participants withdrawing energy, to the extent virtual supply offers were not assessed RSG costs, refunds were due for the period starting April 25, 2006.

The electric utility recorded a $1.7 million ($1.0 million net-of-tax) charge to earnings in the first quarter of 2007 based on an internal estimate of the net impact of MISO reallocating RSG charges in response to the FERC order on rehearing. In May 2007, MISO informed affected market participants of the impact of reallocating charges based on its interpretation of the FERC order on rehearing. Based on MISO's interpretation of the order on rehearing, the electric utility estimated the reallocation of charges would not have a significant impact on earnings previously recognized by the electric utility. Accordingly, the electric utility revised its first quarter estimated charge of $1.7 million ($1.0 million net-of-tax) to zero in the second quarter of 2007.

On March 15, 2007 the FERC also directed MISO to make another compliance filing that the FERC addressed on November 7, 2008 (RSG Compliance Order III). In RSG Compliance Order III, the FERC concluded that its interpretation in RSG III regarding the RSG rate denominator was in error and that a different interpretation applied. On November 10, 2008 the FERC issued an order on the paper hearing finding the current RSG rate unjust and unreasonable and accepting an interim rate that applied RSG charges to all virtual sales until such time as MISO makes a subsequent filing of the new RSG rate. In response to RSG Compliance Order III, MISO made another compliance filing on December 8, 2008 in which it proposed to re-resettle the RSG charges and cost allocations back to market start to correct its previous resettlement completed in January 2008 that was based on the FERC's interpretation of the RSG rate and billing determinants affirmed in RSG III. In addition to correcting the RSG rate denominator to limit it to only virtual sales associated with actual physical energy withdrawals, MISO proposed additional corrections designed to reduce the denominator. Both changes will increase the RSG rate that the electric utility must pay. Also, on November 11, 2008 the FERC issued an order on rehearing of the November 28, 2007 order on complaint. Again, where the revenue from RSG charges collected is not sufficient to make RSG payments to suppliers, MISO recovers the shortage through an uplift charge from all load.

The electric utility requested rehearing of both November 10, 2008 orders (in conjunction with the FERC's RSG Compliance Order III). If the FERC denies rehearing, the electric utility will likely seek review at the District of Columbia Circuit (D.C. Circuit). The electric utility's principal concern in these proceedings was to ensure that the FERC did not impose refunds prior to the August 10, 2007 refund effective date. The FERC did not impose such refunds but did offer an interpretation in support of its decision in RSG Compliance Order III (in ER04-691 docket) that would subject the electric utility to further RSG refunds and resettlements prior to August 10, 2007.

Since 2006, the electric utility has been a party to litigation before the FERC regarding the application of RSG charges to market participants who withdraw energy from the market or engage in financial-only, virtual sales of energy into the market or both. These litigated proceedings occurred in several electric rate and complaint dockets before the FERC and several of the FERC's orders are on review before the United States Court of Appeals for the D.C. Circuit. These proceedings create potential contingent liabilities in three separate periods for the electric utility: (1) April 1, 2005 through April 24, 2006; (2) April 25, 2006 through August 9, 2007; and (3) August 10, 2007 forward. The electric utility identified and assessed potential contingent RSG liabilities under various scenarios depending on the time period over which the FERC ultimately orders RSG refunds. The electric utility accrued a liability in 2008 based on the outcome it determined to be most probable. The Company does not know when these litigation proceedings will conclude.

Transmission Practices Audit--The FERC'S Office of Enforcement, formerly referred to as the Division of Audits of the Office of Market Oversight and Investigations, commenced an audit in 2005 of the electric utility's transmission practices for the period January 1, 2003 through August 31, 2005. The purpose of the audit was to determine whether the electric utility's transmission practices were in compliance with the FERC's applicable rules, regulations and tariff requirements and whether the implementation of the electric utility's waivers from the requirements of Order No. 889 and Order No. 2004 appropriately restricted access to transmission information that would benefit the electric utility's off-system sales. FERC staff identified two of the electric utility's transmission practices that it believed were out of compliance. The electric utility believes its actions were in compliance with the MISO tariff but rather than litigate, it entered into a Stipulated Settlement Agreement with FERC staff resolving all issues related to the audit. The FERC approved the settlement agreement on May 29, 2008.

FERC Order (IN08-6-000) issued May 29, 2008 resolves alleged network transmission service violations by the electric utility of MISO's TEMT. The electric utility agreed to pay $547,000 plus interest of $141,000 to the Low Income Home Energy Assistance Program administered by the three states served by the electric utility. This amount represents profits earned by the electric utility on transactions FERC staff believes incorrectly utilized network transmission service under MISO's TEMT. Enforcement staff did not seek to impose a compliance monitoring plan on the electric utility because the MISO's Day 2 market is now operational and its member utilities no longer schedule transmission within the system.

Big Stone II Project

On June 30, 2005 the electric utility 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. The three primary agreements are the Participation Agreement, the Operation and Maintenance Agreement and the Joint Facilities Agreement. Central Minnesota Municipal Power Agency, Great River Energy, Heartland Consumers Power District, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., Southern Minnesota Municipal Power Agency and Western Minnesota Municipal Power Agency are parties to all three agreements. In September 2007, Great River Energy and Southern Minnesota Municipal Power Agency withdrew from the project. The five remaining project participants decided to downsize the proposed plant's nominal generating capacity from 630 megawatts to between 500 and 580 megawatts. New procedural schedules were established in the various project-related proceedings, which take into consideration the optimal plant configuration decided on by the remaining participants. NorthWestern Corporation, one of the co-owners of the existing Big Stone Plant, is an additional party to the Joint Facilities Agreement.

In the fourth quarter of 2005, the participating utilities filed applications with the MPUC for a transmission Certificate of Need and a Route Permit for the Minnesota portion of the Big Stone II transmission line. On January 15, 2009 the MPUC approved, by a vote of 5-0, a motion to grant the Certificate of Need and Route Permit for the Minnesota portion of the Big Stone II transmission line. The motion involved numerous elements, including the following:

- That there is reasonable assurance that Big Stone II would be more cost-effective than renewable energy beyond the statutory levels of renewable energy based on accepted estimates of construction costs and carbon dioxide;
- That the 345 kV transmission project is necessary based on identified regional and state transmission needs; and
- That the project presents risks requiring additional measures to protect the applicants' ratepayers.

Therefore, the MPUC determined to grant the Certificate of Need subject to a number of additional conditions pending issuance of a final order, including but not limited to: (1) fulfilling various requirements relating to renewable energy goals, energy efficiency, community-based energy development projects and emissions reduction; (2) that the generation plant be built as a "carbon capture retrofit ready" facility; (3) that the applicants report to the MPUC on the feasibility of building the plant using ultra-supercritical technology; and (4) that the applicants achieve specific limits on construction cost at $3000/kilowatt and carbon dioxide costs at $26/ton.

The Certificate of Need and Route Permit are required by state law and would allow the Big Stone II utilities to construct and upgrade 112 miles of electric transmission lines in western Minnesota for delivery of power from the Big Stone site and from numerous other planned generation projects, most of which are wind energy.

The electric utility's integrated resource plan (IRP) includes generation from Big Stone II beginning in 2013 to accommodate load growth and to replace expiring purchased power contracts and older coal-fired base-load generation units scheduled for retirement. On June 5, 2008 the MPUC deferred approval of the electric utility's 2006-2020 IRP, originally filed in 2005. The addition of 160 megawatts of wind generation in the IRP was approved early in 2007 and, on January 15, 2009, the MPUC approved the electric utility's 2006-2020 IRP in its entirety. As of the date of this report, the MPUC had not issued a written order reflecting its decision. This 2006-2020 IRP includes new renewable wind generation and significant demand-side management including conservation, new baseload including the proposed Big Stone II power plant, natural gas-fired peaking plants and wholesale energy purchases.

On August 27, 2008 the NDPSC determined that the electric utility's participation in Big Stone II was prudent in a range of 121.8 to 130 megawatts. The NDPSC decision has been appealed to Burleigh County District Court by interveners in the matter. On November 20, 2008 the South Dakota Board of Minerals and Environment unanimously approved the Big Stone II participating utilities' application for a Prevention of Significant Deterioration (PSD) permit for Big Stone II and a proposed Title V Operating Permit for the Big Stone site. A PSD permit is a pre-construction permit designed to protect air quality. Joint petitioners Sierra Club and Clean Water Action have appealed the administrative decision on the PSD permit to the Circuit Court of Hughes County. The appeal is currently pending before the Court. The issuance of the Title V permit is subject to review by the U.S. Environmental Protection Agency (EPA). On January 22, 2009, the EPA filed a formal objection to the proposed Title V permit. The State of South Dakota has revised and submitted a proposed permit in response to the EPA's objection.

The Big Stone II federal Environmental Impact Statement (EIS) process led by the Western Area Power Administration (WAPA) continues to move forward. WAPA and its third party subcontractor continue to develop the Final EIS, which will include comments on the Draft EIS and the Supplemental Draft EIS, and responses to those comments. WAPA will develop a Record of Decision (ROD) following internal review and approval of the Final EIS. The electric utility anticipates publication of the ROD in the Federal Register in the second quarter of 2009. Financial close, which requires the participants to provide binding financial commitments to support their share of costs, is to occur 90 days after the EIS ROD. No one can predict the exact outcome of any of these proceedings.

The delays in approval of the Big Stone II transmission Certificate of Need in Minnesota and issuance of required permits may delay the availability of Big Stone II as a generation resource. Also, the electric utility has experienced more rapid load growth than was expected since originally filing the IRP in 2005. The electric utility is assessing ways in which to address this potential near-term generation shortfall and has requested authority from the MPUC to immediately acquire up to 110 megawatts of peaking capacity. The MPUC committed to expediting a decision on this request.

As of December 31, 2008 the electric utility has capitalized $11.6 million in costs related to the planned construction of Big Stone II. If the project is abandoned for permitting or other reasons, a portion of these capitalized costs and others incurred in future periods may be subject to expense and may not be recoverable.

3. Regulatory Assets and Liabilities

The following table indicates the amount of regulatory assets and liabilities recorded on the Company's comparative balance sheet:

(in thousands)	December 31, 2008	December 31, 2007
Regulatory Assets:		
Unrecognized Prior Service Costs and Actuarial Losses on Pension Benefits	$ 64,490	$ 26,933
Accrued Cost-of-Energy Revenue	8,982	19,452
Deferred Income Taxes	7,094	8,733
Debt Reacquisition Premiums	3,357	3,745
Minnesota Renewable Resource Rider Accrued Revenues	3,045	--
North Dakota Renewable Resource Rider Accrued Revenues	2,009	--
Minnesota General Rate Case Recoverable Expenses	1,457	--
Accumulated ARO Accretion/Depreciation Adjustment	1,437	345
Deferred Marked-to-Market Losses	1,162	771
MISO Schedule 16 and 17 Deferred Administrative Costs - ND	823	576
MISO Schedule 16 and 17 Deferred Administrative Costs - MN	526	855
Deferred Conservation Improvement Program Costs	280	518
Plant Acquisition Costs	63	107
Total Regulatory Assets	$ 94,725	$ 62,035
Regulatory Liabilities:		
Accumulated Reserve for Estimated Removal Costs	$ 12,091	$ 12,317
Deferred Income Taxes	4,943	4,502
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Gains on Other Postretirement Benefits	834	--
Deferred Marked-to-Market Gains	--	271
Gain on Sale of Division Office Building	139	145
Total Regulatory Liabilities	$ 18,007	$ 17,235
Net Regulatory Asset (Liability) Position	$ 76,718	$ 44,800

The regulatory asset related to prior service costs and actuarial losses on pension benefits and the regulatory liability related to the unrecognized transition obligation, prior service costs and actuarial gains on other postretirement benefits represents benefit costs and actuarial gains subject to recovery or return through rates as they are expensed over the remaining service lives of active employees included in the plans. These unrecognized benefit costs and actuarial gains were required to be recognized as components of Accumulated Other Comprehensive Income in equity under SFAS No. 158, *Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans,* but were determined to be eligible for treatment as regulatory assets based on their probable recovery in future retail electric rates.

Accrued Cost-of-Energy Revenue included in Accrued Utility and Cost-of-Energy Revenues will be recovered over the next 20 months.

The regulatory assets and liabilities related to Deferred Income Taxes result from changes in statutory tax rates accounted for in accordance with SFAS No. 109, *Accounting for Income Taxes*.

Debt Reacquisition Premiums included in Unamortized Debt Expense are being recovered from electric utility customers over the remaining original lives of the reacquired debt issues, the longest of which is 23.7 years.

Minnesota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying 2008 renewable resource costs incurred to serve Minnesota customers since January 1, 2008 that have not been billed to Minnesota customers as of December 31, 2008. Minnesota Renewable Resource Rider Accrued Revenues are expected to be recovered over 15 months, from January 2009 through March 2010.

North Dakota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying 2008 renewable resource costs incurred to serve North Dakota customers since January 1, 2008 that have not been billed to North Dakota customers as of December 31, 2008. North Dakota Renewable Resource Rider Accrued Revenues are expected to be recovered over 13 months, from January 2009 through January 2010.

Minnesota General Rate Case Recoverable Expenses will be recovered over a 36-month period beginning in February 2009 when revised rates established by the recent Minnesota general rate case go into effect.

The Accumulated Reserve for Estimated Removal Costs is reduced for actual removal costs incurred.

All Deferred Marked-to-Market Losses recorded as of December 31, 2008 are related to forward purchases of energy scheduled for delivery prior to March 2009.

MISO Schedule 16 and 17 Deferred Administrative Costs – ND will be recovered over the next 36 months.

MISO Schedule 16 and 17 Deferred Administrative Costs – MN will be recovered over the next 23 months.

Plant Acquisition Costs will be amortized over the next 17 months.

Deferred Conservation Program Costs represent mandated conservation expenditures and incentives recoverable through retail electric rates over the next 18 months.

The remaining regulatory liabilities will be paid to electric customers over the next 30 years.

If for any reason, the Company's regulated businesses cease to meet the criteria for application of SFAS No. 71 for all or part of their operations, the regulatory assets and liabilities that no longer meet such criteria would be removed from the comparative balance sheet and included in the comparative statement of income as an extraordinary expense or income item in the period in which the application of SFAS No. 71 ceases.

4. Forward Contracts Classified as Derivatives

Electricity Contracts

All of the electric utility'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. The electric utility'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 shareholders. The electric utility'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. The electric utility 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.

Of the foward energy sales contracts that are marked to market as of December 31, 2008, 100% are offset by forward energy purchase contracts in terms of volumes and delivery periods.

5. Common Shares

Following is a reconciliation of the Company's common shares outstanding from December 31, 2007 through December 31, 2008:

Common Shares Outstanding, December 31, 2007	29,849,789
Issuances:	
September 2008 Common Stock Offering	5,175,000
Stock Options Exercised	276,685
Executive Officer Stock Performance Awards	62,625
Restricted Stock Issued to Nonemployee Directors	20,000
Restricted Stock Issued to Employees	19,371
Vesting of Restricted Stock Units	3,850
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(22,700)
Common Shares Outstanding, December 31, 2008	35,384,620

In September 2008 the Company completed a public offering of 5,175,000 common shares under its universal shelf registration statement filed with the Securities and Exchange Commission, including 675,000 common shares issued pursuant to the full exercise of the underwriters' overallotment option. The public offering price was $30 per share. Net proceeds from the sale of the common shares after deducting underwriting discounts and commissions and offering expenses were $148.8 million. The net proceeds were used to finance the construction of Otter Tail Power Company's 32 wind turbines and collector system at the Ashtabula Wind Center in Barnes County, North Dakota and the expansion of DMI's wind tower manufacturing facilities in Tulsa, Oklahoma and West Fargo, North Dakota.

Stock Incentive Plan
The 1999 Stock Incentive Plan, as amended (Incentive Plan), provides for the grant of stock options, stock appreciation rights, restricted stock, restricted stock units, performance awards, and other stock and stock-based awards. A total of 3,600,000 common shares are authorized for granting stock awards, of which 1,017,326 were still available as of December 31, 2008 under the Incentive Plan, which terminates on December 13, 2013.

Employee Stock Purchase Plan
The 1999 Employee Stock Purchase Plan (Purchase Plan) allows eligible employees to purchase the Company's common shares at 85% of the market price at the end of each six-month purchase period. The number of common shares authorized to be issued under the Purchase Plan is 900,000, of which 330,565 were still available for purchase as of December 31, 2008. At the discretion of the Company, shares purchased under the Purchase Plan can be either new issue shares or shares purchased in the open market. To provide shares for the Purchase Plan, 49,684 common shares were purchased in the open market in 2008 and 52,558 common shares were purchased in the open market in 2007. The shares to be purchased by employees participating in the Purchase Plan are not considered dilutive for the purpose of calculating diluted earnings per share during the investment period.

Dividend Reinvestment and Share Purchase Plan
On August 30, 1996 the Company filed a shelf registration statement with the Securities and Exchange Commission (SEC) for the issuance of up to 2,000,000 common shares pursuant to the Company's Automatic Dividend Reinvestment and Share Purchase Plan (the Plan), which permits shares purchased by shareholders or customers who participate in the Plan to be either new issue common shares or common shares purchased in the open market. The Company's shelf registration statement expired on December 1, 2008 and was replaced by an automatically effective shelf registration statement filed by the Company on November 26, 2008 for the issuance of up to 1,000,000 common shares pursuant to the Plan. Since November 2004 the Company has purchased common shares in the open market to provide shares for the Plan.

6. Share-Based Payments

Purchase Plan
The Purchase Plan allows employees through payroll withholding to purchase shares of the Company's common stock at a 15% discount from the average market price on the last day of a six month investment period. Under SFAS No. 123 (revised 2004),

Share-Based Payments (SFAS No. 123(R)), the Company is required to record compensation expense related to the 15% discount. The 15% discount resulted in compensation expense of $275,000 in 2008, $257,000 in 2007 and $235,000 in 2006. The 15% discount is not taxable to the employee and is not a deductible expense for tax purposes for the Company.

Stock Options Granted Under the Incentive Plan

Since the inception of the Incentive Plan in 1999, the Company has granted 2,041,500 options for the purchase of the Company's common stock. All of the options granted had vested or were forfeited as of December 31, 2007. The exercise price of the options granted was the average market price of the Company's common stock on the grant date. Under SFAS No. 123(R) accounting, compensation expense is recorded based on the estimated fair value of the options on their grant date using a fair-value option pricing model. Under SFAS No. 123(R) accounting, the fair value of the options granted has been recorded as compensation expense over the requisite service period (the vesting period of the options). The estimated fair value of all options granted under the Incentive Plan has been based on the Black-Scholes option pricing model.

Under the modified prospective application of SFAS No. 123(R) accounting requirements, the difference between the intrinsic value of nonvested options and the fair value of those options of $362,000 on January 1, 2006 was recognized on a straight-line basis as compensation expense over the remaining 16 months of the options vesting period. Accordingly, the Company recorded compensation expense of $91,000 in 2007 related to options that were not vested as of January 1, 2006.

Presented below is a summary of the stock options activity:

Stock Option Activity	2008		2007	
	Options	Average Exercise Price	Options	Average Exercise Price
Outstanding, Beginning of Year	787,137	$25.73	1,091,238	$25.74
Granted	--	--	--	--
Exercised	276,685	25.23	298,601	25.73
Forfeited	2,750	27.11	5,500	28.85
Outstanding, End of Year	507,702	26.00	787,137	25.73
Exercisable, End of Year	507,702	26.00	787,137	25.73
Cash Received for Options Exercised		$6,981,000		$7,682,000
Fair Value of Options Granted During Year		none granted		none granted

The following table summarizes information about options outstanding as of December 31, 2008:

Options Outstanding and Exercisable			
Range of Exercise Prices	Outstanding and Exercisable as of 12/31/08	Weighted-Average Remaining Contractual Life (yrs)	Weighted-Average Exercise price
$18.80-$21.94	87,242	1.1	$ 19.69
$21.95-$25.07	28,300	6.3	24.93
$25.08-$28.21	307,010	2.9	26.48
$28.22-$31.34	85,150	3.2	31.06

Restricted Stock Granted to Directors

Under the Incentive Plan, restricted shares of the Company's common stock have been granted to members of the Company's Board of Directors as a form of compensation. Under the application of SFAS No. 123(R) accounting requirements, compensation expense related to restricted shares is based on the fair value of the restricted shares on their grant dates. On April 14, 2008 the Company's Board of Directors granted 20,000 shares of restricted stock to the Company's nonemployee directors. The restricted shares vest 25% per year on April 8 of each year in the period 2009 through 2012 and are eligible for full dividend and voting rights. The grant date fair value of each share of restricted stock was $35.345 per share, the average market price on the date of grant.

Presented below is a summary of the status of directors' restricted stock awards for the years ended December 31:

Directors' Restricted Stock Awards	2008		2007	
	Shares	Weighted Average Grant-Date Fair Value	Shares	Weighted Average Grant-Date Fair Value
Nonvested, Beginning of Year	34,100	$ 30.80	32,775	$ 27.27
Granted	20,000	35.345	15,200	35.04
Vested	14,800	29.92	13,875	27.10
Forfeited	--		--	
Nonvested, End of Year	39,300	33.45	34,100	30.80
Compensation Expense Recognized		$ 461,000		$ 454,000
Fair Value of Shares Vested in Year		443,000		376,000

Restricted Stock Granted to Employees

Under the Incentive Plan, restricted shares of the Company's common stock have been granted to employees as a form of compensation. Because of income tax withholding provisions in the restricted stock award agreements related to restricted stock granted to employees prior to 2006, the value of these grants is considered variable, which, under SFAS No. 123(R), requires the offsetting credit to compensation expense to be recorded as a liability. Under the modified prospective application of SFAS No. 123(R) accounting requirements and accounting rules for variable awards, compensation expense related to nonvested restricted shares granted to employees is recorded based on the estimated fair value of the restricted shares on their grant dates and adjusted for the estimated fair value of any nonvested restricted shares on each subsequent reporting date. The reporting date fair value of nonvested restricted shares granted prior to 2006 under this program is based on the average market value of the Company's common stock on the reporting date--$23.15 on December 31, 2008.

In 2006, under SFAS No. 123(R), the amount of compensation expense recorded related to nonvested restricted shares granted to employees was based on the estimated fair value of the restricted stock grants. Under SFAS 123(R) accounting, a current liability account is credited when compensation expense is recorded. Accumulated liabilities related to nonvested restricted shares issued to employees under this program prior to 2006 will be reversed and credited to the Premium on Common Shares equity account as the shares vest.

The fair value of restricted shares issued under the revised restricted stock award agreements is not considered a liability under SFAS No. 123(R), so compensation expense related to awards granted is based on their grant-date fair value and recognized over the vesting period of the awards with the offsetting credit charged directly to equity.

On April 14, 2008 the Company's Board of Directors granted 17,600 shares of restricted stock to the Company's executive officers and 1,771 shares of restricted stock to a key employee under the Incentive Plan. The restricted shares vest 25% per year on April 8 of each year in the period 2009 through 2012 and are eligible for full dividend and voting rights. The grant date fair value of each share of restricted stock was $35.345 per share, the average market price on the date of grant.

Presented below is a summary of the status of employees' restricted stock awards for the years ended December 31:

Employees' Restricted Stock Awards	2008		2007	
	Shares	Weighted Average Fair Value	Shares	Weighted Average Fair Value
Nonvested, Beginning of Year	24,058	$ 35.46	31,666	$ 31.47
Granted	19,371	35.345	17,300	35.82
Variable/Liability Awards Vested	4,808	34.85	24,608	35.09
Nonvariable Awards Vested	4,475	35.80	300	35.30
Forfeited	--		--	
Nonvested, End of Year	34,146	34.72	24,058	35.46
Compensation Expense Recognized		$ 434,000		$ 549,000
Fair Value of Variable Awards Vested/Liability Paid		168,000		863,000
Fair Value of Nonvariable Awards Vested		160,000		11,000

Restricted Stock Units Granted to Employees

On April 14, 2008 the Company's Board of Directors granted 26,050 restricted stock units to key employees under the Incentive Plan payable in common shares on April 8, 2012, the date the units vest. The grant date fair value of each restricted stock unit was $30.81 per share. Also on April 14, 2008 the Company's Board of Directors approved the award of 600 restricted stock units to be granted effective July 1, 2008 for another key employee under the Incentive Plan payable in common shares on July 1, 2011, the date the units vest. The grant date fair value of these restricted stock units was $35.55 per share. The weighted average contractual term of stock units outstanding as of December 31, 2008 is 2.6 years.

Presented below is a summary of the status of employees' restricted stock unit awards for the years ended December 31:

Employees' Restricted Stock Unit Awards	2008		2007	
	Restricted Stock Units	Weighted Average Grant-Date Fair Value	Restricted Stock Units	Weighted Average Grant-Date Fair Value
Nonvested, Beginning of Year	55,480	$ 26.66	38,615	$ 24.65
Granted	26,650	30.92	23,450	30.07
Converted	3,850	25.93	4,850	26.95
Forfeited	4,695	28.07	1,735	27.03
Nonvested, End of Year	73,585	28.13	55,480	26.66
Compensation Expense Recognized		$ 535,000		$ 383,000
Fair Value of Units Converted in Year		100,000		131,000

Stock Performance Awards granted to Executive Officers

The Compensation Committee of the Company's Board of Directors has approved stock performance award agreements under the Incentive Plan for the Company's executive officers. Under these agreements, the officers could be awarded shares of the Company's common stock based on the Company's total shareholder return relative to that of its peer group of companies in the Edison Electric Institute (EEI) Index over a three-year period beginning on January 1 of the year the awards are granted. The number of shares earned, if any, will be awarded and issued at the end of each three-year performance measurement period. The participants have no voting or dividend rights under these award agreements until the shares are issued at the end of the performance measurement period. Under SFAS No. 123(R) accounting requirements, the amount of compensation expense recorded related to awards granted is based on the estimated grant-date fair value of the awards as determined under a Monte Carlo valuation method.

On April 14, 2008 the Company's Board of Directors granted performance share awards to the Company's executive officers under the Incentive Plan for the 2008-2010 performance measurement period.

The offsetting credit to amounts expensed related to the stock performance awards is included in common shareholders' equity. The table below provides a summary of stock performance awards granted and amounts expensed related to the stock performance awards:

Performance Period	Maximum Shares Subject to Award	Shares Used to Estimate Expense	Fair Value	Expense Recognized in the Year Ended December 31,		Shares Awarded
				2008	2007	
2008-2010	114,800	70,843	$37.59	$ 888,000	$ --	
2007-2009	109,000	67,263	$38.01	852,000	852,000	
2006-2008	88,050	58,700	$25.95	508,000	508,000	29,350
2005-2007	75,150	50,872	$22.10	--	375,000	62,625
2004-2006	70,500	23,500	$23.90	--	--	23,500
Total				$2,248,000	$1,735,000	115,475

As of December 31, 2008 the total remaining unrecognized amount of compensation expense related to stock-based compensation for all stock-based payment programs was approximately $5.8 million (before income taxes), which will be amortized over a weighted-average period of 2.2 years.

7. Retained Earnings Restriction

The Company's Articles of Incorporation, as amended, contain provisions that limit the amount of dividends that may be paid to common shareholders by the amount of any declared but unpaid dividends to holders of the Company's cumulative preferred shares. Under these provisions none of the Company's retained earnings were restricted at December 31, 2008.

8. Commitments and Contingencies

At December 31, 2008 the electric utility had commitments under contracts in connection with construction programs aggregating approximately $30,210,000. For capacity and energy requirements, the electric utility has agreements extending through 2032 at annual costs of approximately $23,846,000 in 2009, $11,552,000 in 2010, $5,565,000 in 2011, $5,565,000 in 2012 and $5,556,000 in 2013, and $87,729,000 for the years beyond 2013.

The electric utility has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. These contracts expire in 2010 and 2016. In total, the electric utility is committed to the minimum purchase of approximately $153,988,000 or to make payments in lieu thereof, under these contracts. The FCA mechanism lessens the risk of loss from market price changes because it provides for recovery of most fuel costs.

The amounts of future operating lease payments are as follows in thousands:

2009	$ 2,826
2010	2,469
2011	1,712
2012	1,216
2013	1,216
Later years	2,836
Total	$ 12,275

The electric future operating lease payments are primarily related to coal rail-car leases. Rent expense was $2,633,000 for 2008 and $2,461,000 for 2007.

<u>Sierra Club Complaint</u>
On June 10, 2008 the Sierra Club filed a complaint in the U.S. District Court for the District of South Dakota (Northern Division) against the Company and two other co-owners of Big Stone Generating Station (Big Stone). The complaint alleges certain violations of the Prevention of Significant Deterioration and New Source Performance Standards (NSPS) provisions of the Clean Air Act and certain violations of the South Dakota State Implementation Plan (South Dakota SIP). The action further alleges the defendants modified and operated Big Stone without obtaining the appropriate permits, without meeting certain emissions limits and NSPS requirements and without installing appropriate emission control technology, all allegedly in violation of the Clean Air Act and the South Dakota SIP. The Sierra Club alleges the defendants' actions have contributed to air pollution and visibility impairment and have increased the risk of adverse health effects and environmental damage. The Sierra Club seeks both declaratory and injunctive relief to bring the defendants into compliance with the Clean Air Act and the South Dakota SIP and to require the defendants to remedy the alleged violations. The Sierra Club also seeks unspecified civil penalties, including a beneficial mitigation project. The Company believes these claims are without merit and that Big Stone has been and is being operated in compliance with the Clean Air Act and the South Dakota SIP. The ultimate outcome of these matters cannot be determined at this time.

<u>Federal Power Act Complaint</u>
On August 29, 2008 Renewable Energy System Americas, Inc. (RES), a developer of wind generation and PEAK Wind Development, LLC (PEAK Wind), a group of landowners in Barnes County, North Dakota, filed a complaint with the FERC alleging that the electric utility and Minnkota Power Cooperative, Inc. (Minnkota) had acted together in violation of the Federal Power Act (FPA) to deny RES/PEAK Wind access to the Pillsbury Line, an interconnection facility which Minnkota owns to interconnect generation projects being developed by the electric utility and NextEra Energy Resources, Inc.(fka FPL Energy, Inc.) (NextEra). RES/PEAK Wind asked that (1) the FERC order Minnkota to interconnect its Glacier Ridge project to the Pillsbury Line, or in the alternative, (2) the FERC direct MISO to interconnect the Glacier Ridge project to the Pillsbury Line. RES and Peak Wind also requested that the electric utility, Minnkota and NextEra pay any costs associated with interconnecting the Glacier Ridge Project to the MISO transmission system which would result from the interconnection of the Pillsbury Line to the Minnkota transmission system, and that the FERC assess civil penalties against the electric utility. The electric utility answered the Complaint on September 29, 2008, denying the allegations of RES and PEAK Wind and requesting that the FERC dismiss the Complaint. On October 14, 2008, RES and PEAK Wind filed an Answer to the electric utility's Answer and, restated the allegations included in the initial Complaint. RES and PEAK Wind also added a request that the FERC rescind both the electric utility's waiver from the FERC Standards of Conduct and its market-based rate authority. On October 28, 2008, the electric utility filed a Reply, denying the allegations made by RES and PEAK Wind in its Answer. By Order issued on December 19, 2008, the FERC set the Complaint for hearing and established settlement procedures. The parties are engaged in settlement discussions. The Company believes the claims that the electric utility has violated the FPA are without merit. The ultimate outcome of this matter cannot be determined at this time.

The Company is a party to litigation arising in the normal course of business. The Company regularly analyzes current information and, as necessary, provides accruals for liabilities that are probable of occurring and that can be reasonably estimated. The Company believes the effect on its comparative results of operations, financial position and cash flows, if any, for the disposition of all matters pending as of December 31, 2008 will not be material.

9. Short-Term and Long-Term Borrowings

Short-Term Debt

The following table presents the status of the Company's line of credit as of December 31, 2008:

(in thousands)	Line Limit	In Use on December 31, 2008	Restricted due to Outstanding Letters of Credit	Available on December 31, 2008
Electric Utility Credit Agreement	$ 170,000	$ 27,065	--	$ 142,935

The weighted average interest rates on consolidated short-term debt outstanding on December 31, 2008 and 2007 were 2.8% and 6.3%, respectively. The weighted average interest rate paid on consolidated short-term debt was 4.1% in 2008 and 6.0% in 2007.

On July 30, 2008 Otter Tail Corporation, dba Otter Tail Power Company replaced its credit agreement with U.S. Bank National Association, which provided for a $75 million line of credit, with a new credit agreement providing for a $170 million line of credit with an accordion feature whereby the line can be increased to $250 million as described in the new credit agreement. The new credit agreement (the Electric Utility Credit Agreement) is between Otter Tail Corporation, dba Otter Tail Power Company and JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association and Merrill Lynch Bank USA, as Banks, U.S Bank National Association, as a Bank and as agent for the Banks, and Bank of America, N.A., as a Bank and as Syndication Agent. The Electric Utility Credit Agreement is an unsecured revolving credit facility that the electric utility can draw on to support the working capital needs and other capital requirements of its operations. Borrowings under this line of credit bear interest at LIBOR plus 0.5%, subject to adjustment based on the ratings of the Company's senior unsecured debt. The Electric Utility Credit Agreement contains a number of restrictions on the business of the electric utility, including restrictions on its ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The Electric Utility Credit Agreement also contains affirmative covenants and events of default. The Electric Utility Credit Agreement is subject to renewal on July 30, 2011.

Long-Term Debt

At closings completed in August 2007 and October 2007, the Company issued $155 million aggregate principal amount of its senior unsecured notes, in a private placement transaction, to the purchasers named in a note purchase agreement (the 2007 Note Purchase Agreement) dated August 20, 2007. These notes were issued in four series: $33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, due 2017 (the Series A Notes); $30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022 (the Series B Notes); $42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027 (the Series C Notes); and $50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037 (the Series D Notes). On August 20, 2007, $12 million aggregate principal amount of the Series C Notes and $13 million aggregate principal amount of the Series D Notes were issued and sold pursuant to the 2007 Note Purchase Agreement. The remaining $30 million aggregate principal amount of the Series C Notes and $37 million aggregate principal amount of the Series D Notes, as well as the Series A Notes and the Series B Notes, were issued and sold by the Company at a second closing on October 1, 2007. The net proceeds from the second closing were used to retire $40 million aggregate principal amount of the Company's 5.625% Series of Insured Senior Notes due October 1, 2017 and $25 million aggregate principal amount of the Company's 6.80% Series of Senior Notes due October 1, 2032 on October 15, 2007, to pay down lines of credit and to fund capital expenditures.

In February 2007 the Company entered into a note purchase agreement (the Cascade Note Purchase Agreement) with Cascade Investment L.L.C. (Cascade) pursuant to which the Company agreed to issue to Cascade, in a private placement transaction, $50 million aggregate principal amount of the Company's senior notes due November 30, 2017 (the Cascade Note). On December 14, 2007 the Company issued the Cascade Note. The Cascade Note bears interest at a rate of 5.778% per annum. The terms of the Cascade Note Purchase Agreement are substantially similar to the terms of the note purchase agreement entered into in connection with the issuance of the Company's $90 million 6.63% senior notes due December 1, 2011 (the 2001 Note Purchase Agreement). The proceeds of this financing were used to redeem the Company's $50 million 6.375% Senior Debentures due December 1, 2007. Cascade owned approximately 9.6% of the Company's outstanding common stock as of December 31, 2008.

Each of the Cascade Note Purchase Agreement, the 2007 Note Purchase Agreement, and the 2001 Note Purchase Agreement states the Company 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. Each of the Cascade Note Purchase Agreement and the 2001 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require the Company 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 respective note purchase agreements. The 2007 Note Purchase Agreement states the Company 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 the Company.

The 2001 Note Purchase Agreement, the 2007 Note Purchase Agreement and the Cascade Note Purchase Agreement contain a number of restrictions on the businesses of the Company and its subsidiaries. In each case these include restrictions on the ability of the Company and certain of its subsidiaries 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 Company's obligations under the 2001 Note Purchase Agreement and the Cascade Note Purchase Agreement are guaranteed by certain of its subsidiaries.

The aggregate amounts of maturities on bonds outstanding and other long-term obligations at December 31, 2008 for each of the next five years are $2,328,572 for 2009, $2,328,568 for 2010, $90,000,000 for 2011, $10,400,000 for 2012 and $0 for 2013.

Financial Covenants

The Electric Utility Credit Agreement, the 2001 Note Purchase Agreement, the Cascade Note Purchase Agreement, the 2007 Note Purchase Agreement, the Lombard US Equipment Finance note and the financial guaranty insurance policy with Ambac Assurance Corporation relating to the Company's pollution control refunding bonds contain covenants by the Company to not permit its debt-to-total capitalization ratio to exceed 60% or permit its interest and dividend coverage ratio (or in the case of the Cascade Note Purchase Agreement, its interest coverage ratio) to be less than 1.5 to 1. The Company's Credit and Note Purchase Agreements do not contain any provisions that would trigger an acceleration of the Company's debt caused by credit rating levels assigned to the Company by rating agencies. The Company was in compliance with all of the financial covenants under its financing agreements as of December 31, 2008.

10. Pension Plan and Other Postretirement Benefits

The following footnote reflects the adoption of SFAS No. 158, *Accounting for Defined Benefit Pension and Other Postretirement Plans,* in December 2006. The Company determined that the balance of unrecognized net actuarial losses, prior service costs and the SFAS No. 106 transition obligation related to regulated utility activities would be subject to recovery through rates as those balances are amortized to expense and the related benefits are earned. Therefore, the Company charged those unrecognized amounts to regulatory asset accounts under SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, rather than to Accumulated Other Comprehensive Losses in equity as prescribed by SFAS No. 158.

Pension Plan

The Company's noncontributory funded pension plan covers substantially all electric utility and corporate employees hired prior to January 1, 2006. 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. The Company reserves the right to discontinue the plan but no change or discontinuance may affect the pensions theretofore vested.

The pension plan has a trustee who is responsible for pension payments to retirees. Five investment managers are responsible for managing the plan's assets. An independent actuary assists the Company 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. None of the plan assets are invested in common stock, preferred stock or debt securities of the Company.

Components of net periodic pension benefit cost:

(in thousands)	2008	2007
Service Cost--Benefit Earned During the Period	$ 4,630	$ 4,837
Interest Cost on Projected Benefit Obligation	11,325	10,790
Expected Return on Assets	(13,968)	(12,948)
Amortization of Prior-Service Cost	742	742
Amortization of Net Actuarial Loss	169	1,091
Net Periodic Pension Cost	$ 2,898	$ 4,512

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

	2008	2007
Discount Rate	6.25%	6.00%
Long-Term Rate of Return on Plan Assets	8.50%	8.50%
Rate of Increase in Future Compensation Level	3.75%	3.75%

The following table presents amounts recognized in the comparative balance sheets as of December 31:

(in thousands)	2008	2007
Regulatory Assets:		
Unrecognized Prior Service Cost	$ 3,303	$ 4,018
Unrecognized Actuarial Loss	56,652	17,115
Total Regulatory Assets	59,955	21,133
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	(55)	(72)
Unrecognized Actuarial Loss	(943)	(307)
Total Accumulated Other Comprehensive Loss	(998)	(379)
Deferred Income Taxes	(666)	(252)
Prepaid Pension Cost	6,595	7,493
Net Amount Recognized – Noncurrent Liability	$ (55,024)	$ (14,271)

Funded status as of December 31:

(in thousands)	2008	2007
Accumulated Benefit Obligation	$(153,676)	$(154,373)
Projected Benefit Obligation	$(182,559)	$(185,206)
Fair Value of Plan Assets	127,535	170,935
Funded Status	$ (55,024)	$ (14,271)

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's benefit obligations and prepaid pension cost over the two-year period ended December 31, 2008:

(in thousands)	2008	2007
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$ 170,935	$ 167,508
Actual Return on Plan Assets	(36,523)	8,013
Discretionary Company Contributions	2,000	4,000
Benefit Payments	(8,877)	(8,586)
Fair Value of Plan Assets at December 31	$ 127,535	$ 170,935
Estimated Asset Return	(21.94)%	4.85%
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 185,206	$ 186,760
Service Cost	4,630	4,837
Interest Cost	11,325	10,790
Benefit Payments	(8,877)	(8,586)
Actuarial Gain	(9,725)	(8,595)
Projected Benefit Obligation at December 31	$ 182,559	$ 185,206
Reconciliation of Prepaid Pension Cost:		
Prepaid Pension Cost at January 1	$ 7,493	$ 8,005
Net Periodic Pension Cost	(2,898)	(4,512)
Discretionary Company Contributions	2,000	4,000
Prepaid Pension Cost at December 31	$ 6,595	$ 7,493

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

	2008	2007
Discount Rate	6.70%	6.25%
Rate of Increase in Future Compensation Level	3.75%	3.75%

To develop the expected long-term rate of return on assets assumption, the Company considered the historical returns and the future expectations for returns for each asset class, as well as the target asset allocation of the pension portfolio.

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

The assumed rate of return on pension fund assets for the determination of 2009 net periodic pension cost is 8.50%.

Measurement Dates:	2008	2007
Net Periodic Pension Cost	January 1, 2008	January 1, 2007
End of Year Benefit Obligations	January 1, 2008 projected to December 31, 2008	January 1, 2007 projected to December 31, 2007
Market Value of Assets	December 31, 2008	December 31, 2007

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 in 2009 are:

(in thousands)	2009
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ 704
Amortization of Unrecognized Actuarial Loss	21
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	20
Amortization of Unrecognized Actuarial Loss	1
Total Estimated Amortization	$ 746

Cash flows--The Company is not required to make a contribution to the pension plan in 2009.

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

(in thousands)	2009	2010	2011	2012	2013	Years 2014-2018
	$9,123	$9,286	$9,390	$9,766	$10,139	$59,081

The Company's pension plan asset allocations at December 31, 2008 and 2007, by asset category are as follows:

Asset Allocation	2008	2007
Large Capitalization Equity Securities	39.6%	47.1%
Small Capitalization Equity Securities	9.2%	10.7%
International Equity Securities	8.3%	10.4%
Total Equity Securities	57.1%	68.2%
Cash and Fixed-Income Securities	42.9%	31.8%
	100.0%	100.0%

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

- The Plan is managed to operate in perpetuity.
- The Plan will meet the pension benefit obligation payments of the Company.
- 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 the Company's Retirement Plans Administrative 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.

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 Retirement Plans Administrative Committee and/or investment managers, and required cash flows to and from the Plan. The tactical range provides flexibility for the investment managers' portfolios to vary around the target allocation without the need for immediate rebalancing.

The Company's Retirement Plans Administrative Committee monitors actual asset allocations and directs contributions and withdrawals toward maintaining current targeted allocation percentages listed in the table below.

Asset Allocation	Strategic Target	Tactical Range
Large capitalization equity securities	48%	40%-55%
Small capitalization equity securities	12%	9%-15%
International equity securities	10%	5%-15%
Total equity securities	70%	60%-80%
Fixed-income securities	30%	20%-40%

Executive Survivor and Supplemental Retirement Plan (ESSRP)

The ESSRP is an unfunded, nonqualified benefit plan for executive officers and certain key management employees. The ESSRP provides defined benefit payments to these employees on their retirements for life or to their beneficiaries on their deaths for a 15-year postretirement period. Life insurance carried on certain plan participants is payable to the Company on the employee's death. There are no plan assets in this nonqualified benefit plan due to the nature of the plan.

Components of net periodic pension benefit cost:

(in thousands)	2008	2007
Service Cost--Benefit Earned During the Period	$ 691	$ 626
Interest Cost on Projected Benefit Obligation	1,535	1,451
Amortization of Prior-Service Cost	66	67
Amortization of Net Actuarial Loss	480	540
Net Periodic Pension Cost	$ 2,772	$ 2,684

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

	2008	2007
Discount Rate	6.25%	6.00%
Rate of Increase in Future Compensation Level	4.70%	4.71%

The following table presents amounts recognized in the comparative balance sheets as of December 31:

(in thousands)	2008	2007
Regulatory Assets:		
Unrecognized Prior Service Cost	$ 421	$ 435
Unrecognized Actuarial Loss	4,114	4,841
Total Regulatory Assets	4,535	5,276
Projected Benefit Obligation Liability – Net Amount Recognized	(25,888)	(25,158)
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	(166)	(160)
Unrecognized Actuarial Loss	(1,626)	(1,772)
Total Accumulated Other Comprehensive Loss	(1,792)	(1,932)
Deferred Income Taxes	(1,194)	(1,288)
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$ (18,367)	$ (16,662)

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, 2008 and a statement of the funded status as of December 31 of both years:

(in thousands)	2008	2007
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$ --	$ --
Actual Return on Plan Assets	--	--
Employer Contributions	1,067	1,079
Benefit Payments	(1,067)	(1,079)
Fair Value of Plan Assets at December 31	$ --	$ --
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 25,158	$ 24,783
Service Cost	691	626
Interest Cost	1,535	1,451
Benefit Payments	(1,067)	(1,079)
Plan Amendments	63	--
Actuarial Gain	(492)	(623)
Projected Benefit Obligation at December 31	$ 25,888	$ 25,158
Reconciliation of Funded Status:		
Funded Status at December 31	$ (25,888)	$ (25,158)
Unrecognized Net Actuarial Loss	6,823	7,795
Unrecognized Prior Service Cost	698	701
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$ (18,367)	$ (16,662)

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

	2008	2007
Discount Rate	6.70%	6.25%
Rate of Increase in Future Compensation Level	4.70%	4.70%

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 2009 are:

(in thousands)	2009
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ 43
Amortization of Unrecognized Actuarial Loss	232
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	28
Amortization of Unrecognized Actuarial Loss	153
Total Estimated Amortization	$ 456

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:

(in thousands)	2009	2010	2011	2012	2013	Years 2014-2018
	$1,114	$1,117	$1,228	$1,288	$1,274	$7,220

Other Postretirement Benefits

The Company provides a portion of health insurance and life insurance benefits for retired electric utility and corporate employees. Substantially all of the Company's electric utility and corporate employees may become eligible for health insurance benefits if they reach age 55 and have 10 years of service. On adoption of SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*, in January 1993, the Company elected to recognize its transition obligation related to postretirement benefits earned of approximately $14,964,000 over a period of 20 years. There are no plan assets.

Components of net periodic postretirement benefit cost:

(in thousands)	2008	2007
Service Cost--Benefit Earned During the Period	$ 1,103	$ 1,098
Interest Cost on Projected Benefit Obligation	2,689	2,565
Amortization of Transition Obligation	748	748
Amortization of Prior-Service Cost	211	(206)
Amortization of Net Actuarial Loss	26	177
Expense Decrease Due to Medicare Part D Subsidy	(1,172)	(1,233)
Net Periodic Postretirement Benefit Cost	$ 3,605	$ 3,149

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

	2008	2007
Discount Rate	6.25%	6.00%

The following table presents amounts recognized in the comparative balance sheets as of December 31:

(in thousands)	2008	2007
Regulatory Asset:		
Unrecognized Transition Obligation	$ 1,454	$ 3,658
Unrecognized Prior Service Cost	1,567	1,781
Unrecognized Net Actuarial Gain	(3,855)	(4,915)
Net Regulatory (Liability) Asset	(834)	524
Projected Benefit Obligation Liability – Net Amount Recognized	(32,621)	(30,488)
Accumulated Other Comprehensive Loss:		
Unrecognized Transition Obligation	(923)	(50)
Unrecognized Prior Service Cost	(26)	(24)
Unrecognized Net Actuarial Gain	64	67
Accumulated Other Comprehensive Loss	(885)	(7)
Deferred Income Taxes	(590)	(5)
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$ (31,980)	$ (29,952)

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's projected benefit obligations and accrued postretirement benefit cost over the two-year period ended December 31, 2008:

(in thousands)	2008	2007
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$ --	$ --
Actual Return on Plan Assets	--	--
Company Contributions	1,577	1,459
Benefit Payments (Net of Medicare Part D Subsidy)	(3,392)	(3,127)
Participant Premium Payments	1,815	1,668
Fair Value of Plan Assets at December 31	$ --	$ --
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 30,488	$ 32,254
Service Cost (Net of Medicare Part D Subsidy)	902	890
Interest Cost (Net of Medicare Part D Subsidy)	1,874	1,776
Benefit Payments (Net of Medicare Part D Subsidy)	(3,392)	(3,127)
Participant Premium Payments	1,815	1,668
Actuarial Loss (Gain)	934	(2,973)

Projected Benefit Obligation at December 31	$ 32,621	$ 30,488
Reconciliation of Accrued Postretirement Cost:		
Accrued Postretirement Cost at January 1	$ (29,952)	$ (28,262)
Expense	(3,605)	(3,149)
Net Company Contribution	1,577	1,459
Accrued Postretirement Cost at December 31	$ (31,980)	$ (29,952)

	2008	2007
Discount Rate	6.70%	6.25%

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

Assumed healthcare cost-trend rates as of December 31:

	2008	2007
Healthcare Cost-Trend Rate Assumed for Next Year Pre-65	7.40%	8.00%
Healthcare Cost-Trend Rate Assumed for Next Year Post-65	8.00%	9.00%
Rate at Which the Cost-Trend Rate is Assumed to Decline	5.00%	5.00%
Year the Rate Reaches the Ultimate Trend Rate	2017	2012

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 2008 would have the following effects:

(in thousands)	1 point increase	1 point decrease
Effect on the Postretirement Benefit Obligation	$ 3,052	$(2,644)
Effect on Total of Service and Interest Cost	$ 362	$ (298)
Effect on Expense	$ 492	$ (554)

Measurement dates:	2008	2007
Net Periodic Postretirement Benefit Cost	January 1, 2008	January 1, 2007
End of Year Benefit Obligations	January 1, 2008 projected to December 31, 2008	January 1, 2007 projected to December 31, 2007

The estimated net amounts of unrecognized transition obligation and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic postretirement benefit cost in 2009 are:

(in thousands)	2009
Decrease in Regulatory Assets:	
Amortization of Transition Obligation	$ 364
Amortization of Unrecognized Prior Service Cost	204
Amortization of Unrecognized Actuarial Gain	(71)
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Transition Obligation	384
Amortization of Unrecognized Prior Service Cost	6
Amortization of Unrecognized Actuarial Gain	(2)
Total Estimated Amortization	$ 885

Cash flows--The Company expects to contribute $2.4 million net of expected employee contributions for the payment of retiree medical benefits and Medicare Part D subsidy receipts in 2009. The Company expects to receive a Medicare Part D subsidy from the Federal government of approximately $447,000 in 2009. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

(in thousands)	2009	2010	2011	2012	2013	Years 2014-2018
	$2,371	$2,327	$2,468	$2,568	$2,696	$15,163

Leveraged Employee Stock Ownership Plan

The Company has a leveraged employee stock ownership plan for the benefit of all its electric utility employees. Contributions made by the Company were $738,000 for 2008 and $733,000 for 2007.

11. 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 the Company's long-term debt is estimated based on the current rates available to the Company for the issuance of debt. About $10.4 million of the Company's long-term debt, which is subject to variable interest rates, approximates fair value.

	December 31, 2008		December 31, 2007	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Short-Term Investments	$ 6,454	$ 6,454	$ 27,304	$ 27,304
Long-Term Debt	(335,847)	(304,404)	(338,276)	(349,824)

12. Property, Plant and Equipment

(in thousands)	December 31, 2008	December 31, 2007
Electric Plant		
Production	$ 590,252	$ 439,541
Transmission	201,456	191,949
Distribution	337,296	322,107
General	76,643	75,320
Electric Plant	1,205,647	1,028,917
Less Accumulated Depreciation and Amortization	467,855	446,475
Electric Plant Net of Accumulated Depreciation	737,792	582,442
Construction Work in Progress	25,547	33,772
Net Electric Plant	$ 763,339	$ 616,214

The estimated service lives for rate-regulated properties is 5 to 65 years.

	Service Life Range	
(years)	Low	High
Electric Fixed Assets:		
Production Plant	34	62
Transmission Plant	40	55
Distribution Plant	15	55
General Plant	5	65

13. Summary Information of Investees Accounted for Under the Equity Method

See note 1 for further discussion.

	2008	2007
	(in thousands)	
Net property, plant, and equipment	$225,808	$190,473
Current assets	292,905	290,773
Other assets	152,026	132,929
Total assets	$670,739	$614,175
Current and other liabilities	$246,441	$222,844
Long-term liabilities	40,742	43,892
Class B stock options	1,220	1,255
Owner's equity	382,336	346,184
Total liabilities and equity	$670,739	$614,175
Operating revenue	$979,031	$922,012
Operating expenses	950,599	862,119
Operating income	28,432	59,893
Other income, deductions, and interest	(6,925)	(8,635)
Income taxes	8,513	18,047
Net income	$12,994	$33,211

14. Income Taxes

The total income tax expense differs from the amount computed by applying the federal income tax rate (35 percent in 2008 and 2007) to net income before total income tax expense for the following reasons:

	2008	2007
	(in thousands)	
Tax computed at federal statutory rate	$ 10,072	$ 10,879
Increases (decreases) in tax from:		
State income taxes net of federal income tax benefit	805	987
Differences reversing in excess of federal rates	1,089	929
Federal production tax credit	(3,234)	-
Investment tax credit amortization	(1,125)	(1,137)
Dividends received/paid deduction	(718)	(714)
Affordable housing tax credits	(55)	(285)
Section 199 domestic production activities deduction	-	(327)
Permanent and other differences	(267)	(267)
Total income tax expense	$ 6,567	$ 10,065
Overall effective federal and state income tax rate	22.8%	32.3%

	2008	2007
	(in thousands)	
Income tax expense includes the following:		
Charges (credits) related to operations:		
Current federal income taxes	$ (28,929)	$ 6,043
Current state income taxes	(3,575)	(863)
Deferred federal income taxes	33,064	2,701
Deferred state income taxes	4,819	733
Investment tax credit amortization	(1,125)	(1,136)
Total	4,254	7,478
Charges (credits) related to other income and deductions:		
Current federal income taxes	1,942	2,146
Current state income taxes	369	131
Affordable housing tax credits	(55)	(285)
Deferred federal income taxes	49	(847)
Deferred state income taxes	8	1,442
Total income tax expense	$ 6,567	$ 10,065

The Company's deferred tax assets and liabilities were composed of the following on December 31, 2008 and 2007:

	2008	2007
	(in thousands)	
Deferred tax assets		
Amortization of tax credits	$ 4,946	$ 4,505
Vacation accrual	1,320	1,258
Operating reserves	28,487	27,103
Differences related to property	9,581	8,270
Related to North Dakota Wind Tax Credits	35,902	12,989
Other	3,585	427
Total deferred tax assets	83,821	54,552
Deferred tax liabilities		
Differences related to property	(149,993)	(109,710)
Excess tax over book pension	(2,599)	(2,953)
Transfer to regulatory asset	(7,045)	(8,471)
Related to ND Wind Tax Credit	(10,074)	(4,340)
Other	(1,476)	(377)
Total deferred tax liabilities	(171,187)	(125,851)
Deferred income taxes	$ (87,366)	$ (71,299)

On January 1, 2007 the Company adopted the provisions of FIN No. 48. The cumulative effect of adoption of FIN No. 48, which is reported as an adjustment to the beginning balance of retained earnings, was $118,000. As of the date of adoption, the total amount of unrecognized tax benefits for uncertain tax positions was $1,874,000. The amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate was $575,000 as of January 1, 2007.

The following table summarizes the activity related to our unrecognized tax benefits:

(in thousands)	Total
Balance at January 1, 2008	$ 506
Increases Related to Current Year Tax Positions	--
Expiration of the Statute of Limitations for the Assessment of Taxes	(222)
Balance at December 31, 2008	$ 284

The balance of unrecognized tax benefits as of December 31, 2008 would reduce our effective tax rate if recognized. The total amount of unrecognized tax benefits as of December 31, 2008 is not expected to change significantly within the next 12 months. The Company and its subsidiaries file a consolidated U.S. federal income tax return and various state and foreign income tax returns. As of December 31, 2008 the Company is no longer subject to U.S. federal income tax examinations by tax authorities for years before 2005. As of December 31, 2008 the Company's earliest open tax year in which an audit can be initiated by state taxing authorities in the Company's major operating jurisdictions is 2004 for Minnesota and 2005 for North Dakota. Amounts accrued for interest and penalties on tax uncertainties as of December 31, 2008 were not material.

15. Asset Retirement Obligations (AROs)

The Company's AROs are related to coal-fired generation plants, 27 wind turbines located near Langdon, North Dakota and 32 wind turbines at the Ashtabula Wind Energy Center in North Dakota and include site restoration, closure of ash pits, and removal of storage tanks, structures, generators and asbestos. The Company has legal obligations associated with the retirement of a variety of other long-lived tangible assets used in electric operations where the estimated settlement costs are individually and collectively immaterial. The Company has no assets legally restricted for the settlement of any of its AROs.

During 2008, the electric utility recorded new obligations related to the removal of 32 wind turbines located at the Ashtabula Wind Energy Center in Barnes County, North Dakota and restoration of the tower sites and made revisions to previously recorded obligations related to site restoration, closure of ash pits, and removal of storage tanks, structures, generators and asbestos at its coal-fired generation plants.

The measurements used to determine the fair values of electric utility's AROs fall into level 3, of the fair value hierarchy set forth in SFAS No. 157, *Fair Value Measurements*. The electric utility determined the fair value of its future obligations related to the removal of 32 wind turbines located at the Ashtabula Wind Energy Center by engaging an outside engineering firm with expertise in demolition and removal to provide an estimate of the current costs to remove these assets, then projected the costs forward to 2033 using an inflation rate of 3.1% per year and discounted this amount back to its present value using a credit adjusted risk free rate of 9.0%.

During 2007, the Company recorded new obligations related to the removal of 27 wind turbines located near Langdon, North Dakota and restoration of the tower sites but did not make any revisions to previously recorded obligations.

Reconciliations of carrying amounts of the present value of the Company's legal AROs, capitalized asset retirement costs and related accumulated depreciation and a summary of settlement activity for the years ended December 31, 2008 and 2007 are presented in the following table:

(in thousands)	2008	2007
Asset Retirement Obligations		
Beginning Balance	$ 2,447	$ 1,335
New Obligations Recognized	317	1,024
Adjustments Due to Revisions in Cash Flow Estimates	407	--
Accrued Accretion	127	88
Settlements	--	--
Ending Balance	$ 3,298	$ 2,447
Asset Retirement Costs Capitalized		
Beginning Balance	$ 1,309	$ 285
New Obligations Recognized	317	1,024
Adjustments Due to Revisions in Cash Flow Estimates	(565)	--
Settlements	--	--
Ending Balance	$ 1,061	$ 1,309
Accumulated Depreciation - Asset Retirement Costs Capitalized		
Beginning Balance	$ 185	$ 178
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	(34)	--
Accrued Depreciation	28	7
Settlements	--	--
Ending Balance	$ 179	$ 185
Settlements		
Original Capitalized Asset Retirement Cost - Retired	$ --	$ --
Accumulated Depreciation	--	--
Asset Retirement Obligation	$ --	$ --
Settlement Cost	--	--
Gain on Settlement – Deferred Under Regulatory Accounting	$ --	$ --

16. Holding Company Reorganization

Our Board of Directors has authorized a holding company reorganization of our regulated utility business. Following the completion of the holding company reorganization, Otter Tail Power Company, which is currently operated as a division of Otter Tail Corporation, will be operated as a wholly owned subsidiary of the new parent holding company to be named Otter Tail Corporation. In connection with the reorganization, each outstanding Otter Tail Corporation common share will be automatically converted into one common share of the new holding company, and each outstanding Otter Tail Corporation cumulative preferred share will be automatically converted into one cumulative preferred share of the new holding company, having the same terms. The holding company reorganization is subject to approval by Minnesota, North Dakota and South Dakota regulatory agencies and by the Federal Energy Regulatory Commission (FERC), consents from various third parties and certain other conditions. In an order issued on August 18, 2008, the FERC authorized the reorganization subject to certain conditions specified in the order. In an order issued on October 10, 2008, the North Dakota Public Service Commission (NDPSC) approved our application to form a holding company. In a meeting held on October 30, 2008, the South Dakota Public Utilities Commission (SDPUC) approved our application to form a new holding company. The Minnesota Public Utilities Commission (MPUC) approved our request to form a holding company, with certain conditions, at its hearing on December 11, 2008. There remain several business and legal steps that must be accomplished before the reorganization can be completed.

17. Quantitative and Qualitative Disclosures about Market Risk

At December 31, 2008 we had exposure to market risk associated with interest rates because we had $27.1 million in short-term debt outstanding subject to variable interest rates that are indexed to LIBOR plus 0.5% under the Electric Utility Credit Agreement.

The majority of our consolidated long-term debt has fixed interest rates. The interest rate on variable rate long-term debt is reset on a periodic basis reflecting current market conditions. We manage our 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. As of December 31, 2008 we had $10.4 million of long-term debt subject to variable interest rates. Assuming no change in our financial structure, if variable interest rates were to average one percentage point higher or lower than the average variable rate on December 31, 2008, annualized interest expense and pre-tax earnings would change by approximately $104,000.

We have not used interest rate swaps to manage net exposure to interest rate changes related to our portfolio of borrowings. We maintain a ratio of fixed-rate debt to total debt within a certain range. It is our policy to enter into interest rate transactions and other financial instruments only to the extent considered necessary to meet our stated objectives. We do not enter into interest rate transactions for speculative or trading purposes.

The electric utility has market, price and credit risk associated with forward contracts for the purchase and sale of electricity. As of December 31, 2008 the electric utility had recognized, on a pretax basis, $123,000 in net unrealized losses on open forward contracts for the purchase and sale of electricity. 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 the electric utility’s forward contracts for the purchases and sales of electricity are determined by survey of counterparties or brokers used by the electric utility’s power services’ personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. Prices are benchmarked to forward price curves and indices acquired from a third party price forecasting service. Of the forward energy sales contracts that are marked to market as of December 31, 2008, 100% are offset by forward energy purchase contracts in terms of volumes and delivery periods.

We have 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. With the advent of the MISO Day 2 market in April 2005, we made several changes to our energy risk management policy to recognize new trading opportunities created by this new market. Most of the changes were in new volumetric limits and loss limits to adequately manage the risks associated with these new opportunities. In addition, we implemented a Value at Risk (VaR) limit to further manage market price risk. Exposure to price risk on any open positions as of December 31, 2008 was not material.

The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity on our comparative balance sheet as of December 31, 2008 and the change in our comparative balance sheet position from December 31, 2007 to December 31, 2008:

(in thousands)	December 31, 2008
Current Asset – Marked-to-Market Gain	$ 405
Regulatory Asset – Deferred Marked-to-Market Loss	1,162
Total Assets	1,567
Current Liability – Marked-to-Market Loss	(1,690)
Regulatory Liability – Deferred Marked-to-Market Gain	--
Total Liabilities	(1,690)
Net Fair Value of Marked-to-Market Energy Contracts	$ (123)

(in thousands)	Year ended December 31, 2008
Fair Value at Beginning of Year	$ 632
Amount Realized on Contracts Entered into in 2007 and Settled in 2008	(1,169)
Changes in Fair Value of Contracts Entered into in 2007	537
Net Fair Value of Contracts Entered into in 2007 at Year End 2008	--
Changes in Fair Value of Contracts Entered into in 2008	(123)
Net Fair Value at End of Year	$ (123)

The $123,000 in recognized but unrealized net losses on the forward energy purchases and sales marked to market on December 31, 2008 is expected to be realized on physical settlement as scheduled in January and February of 2009.

We have credit risk associated with the nonperformance or nonpayment by counterparties to our forward energy purchases and sales agreements. We have established guidelines and limits to manage credit risk associated with wholesale power purchases and sales. Specific limits are determined by a counterparty’s financial strength. Our credit risk with our largest counterparty on delivered and marked-to-market forward contracts as of December 31, 2008 was $252,000. As of December 31, 2008 we had a net credit risk exposure of $921,000 from 12 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. We had no exposure at December 31, 2008 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 $921,000 credit risk exposure includes net amounts due to the electric utility 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, 2008. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

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

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.

2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.

3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year	17,953			(1,084,878)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value	3,747			2,243,880
4	Total (lines 2 and 3)	3,747			2,243,880
5	Balance of Account 219 at End of Preceding Quarter/Year	21,700			1,159,002
6	Balance of Account 219 at Beginning of Current Year	21,700			1,159,002
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value	(39,478)			(4,140,906)
9	Total (lines 7 and 8)	(39,478)			(4,140,906)
10	Balance of Account 219 at End of Current Quarter/Year	(17,778)			(2,981,904)

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			(1,066,925)		
2					
3			2,247,627		
4			2,247,627	53,960,704	56,208,331
5			1,180,702		
6			1,180,702		
7					
8			(4,180,384)		
9			(4,180,384)	35,124,611	30,944,227
10			(2,999,682)		

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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 (f) 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)	989,799,390	989,799,390
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	214,170,551	214,170,551
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	1,203,969,941	1,203,969,941
9	Leased to Others		
10	Held for Future Use	29,656	29,656
11	Construction Work in Progress	25,546,667	25,546,667
12	Acquisition Adjustments	1,647,128	1,647,128
13	Total Utility Plant (8 thru 12)	1,231,193,392	1,231,193,392
14	Accum Prov for Depr, Amort, & Depl	467,854,874	467,854,874
15	Net Utility Plant (13 less 14)	763,338,518	763,338,518
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	464,836,693	464,836,693
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	1,709,719	1,709,719
22	Total In Service (18 thru 21)	466,546,412	466,546,412
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	1,308,462	1,308,462
33	Total Accum Prov (equals 14) (22,26,30,31,32)	467,854,874	467,854,874

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
					5
					6
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					31
					32
					33

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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)		

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NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
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			16
			17
			18
			19
			20
			21
			22

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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	2,784,786	434,866
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	4,086,760	434,866
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,247,790	196,261
9	(311) Structures and Improvements	59,036,779	811,947
10	(312) Boiler Plant Equipment	185,525,082	7,409,625
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	58,920,094	376,292
13	(315) Accessory Electric Equipment	19,020,077	73,614
14	(316) Misc. Power Plant Equipment	5,155,245	151,770
15	(317) Asset Retirement Costs for Steam Production	285,405	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	329,190,472	9,019,509
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	188,390	52,943
29	(332) Reservoirs, Dams, and Waterways	1,452,891	167,856
30	(333) Water Wheels, Turbines, and Generators	917,114	59,384
31	(334) Accessory Electric Equipment	478,134	
32	(335) Misc. Power PLant Equipment	147,892	
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)	3,492,044	280,183
36	D. Other Production Plant		
37	(340) Land and Land Rights	126,762	
38	(341) Structures and Improvements	4,609,977	41,500
39	(342) Fuel Holders, Products, and Accessories	1,547,234	
40	(343) Prime Movers	30,971,079	573,875
41	(344) Generators	65,000,000	128,123,849
42	(345) Accessory Electric Equipment	1,594,131	
43	(346) Misc. Power Plant Equipment	397,249	24,774
44	(347) Asset Retirement Costs for Other Production	1,024,097	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	105,270,529	128,763,998
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	437,953,045	138,063,690

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	361,482	
49	(352) Structures and Improvements		
50	(353) Station Equipment	55,443,997	7,915,842
51	(354) Towers and Fixtures	4,692,263	
52	(355) Poles and Fixtures	67,062,850	9,552,422
53	(356) Overhead Conductors and Devices	63,948,124	3,107,667
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices	70,010	10,627
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)	191,578,726	20,586,558
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	960,533	
61	(361) Structures and Improvements		
62	(362) Station Equipment	45,034,318	5,210,969
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	54,068,827	2,199,448
65	(365) Overhead Conductors and Devices	41,998,499	1,308,066
66	(366) Underground Conduit	10,879	
67	(367) Underground Conductors and Devices	51,499,989	2,972,616
68	(368) Line Transformers	53,601,585	6,003,190
69	(369) Services	38,269,132	1,956,829
70	(370) Meters	29,086,087	1,839,098
71	(371) Installations on Customer Premises	3,690,933	210,857
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	4,185,545	266,109
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	322,406,327	21,967,182
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	1,276,408	157,768
87	(390) Structures and Improvements	27,016,860	2,425,476
88	(391) Office Furniture and Equipment	7,848,459	412,038
89	(392) Transportation Equipment	24,971,153	2,769,597
90	(393) Stores Equipment	546	
91	(394) Tools, Shop and Garage Equipment	4,008,215	308,887
92	(395) Laboratory Equipment	375,624	
93	(396) Power Operated Equipment	496,188	35,288
94	(397) Communication Equipment	5,222,037	713,953
95	(398) Miscellaneous Equipment		
96	SUBTOTAL (Enter Total of lines 86 thru 95)	71,215,490	6,823,007
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)	71,215,490	6,823,007
100	TOTAL (Accounts 101 and 106)	1,027,240,348	187,875,303
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)	1,027,240,348	187,875,303

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

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
			1,301,974		3
600,149			2,619,503		4
600,149			3,921,477		5
					6
					7
3,204		-1,200	1,439,647		8
14,385			59,834,341		9
1,197,656			191,737,051		10
					11
2,395,364			56,901,022		12
3,737			19,089,954		13
50,926			5,256,089		14
	-36,046		249,359		15
3,665,272	-36,046	-1,200	334,507,463		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			307,623		27
			241,333		28
7,578			1,613,169		29
			976,498		30
			478,134		31
			147,892		32
					33
					34
7,578			3,764,649		35
					36
			126,762		37
8,000			4,643,477		38
			1,547,234		39
82,765			31,462,189		40
			193,123,849		41
			1,594,131		42
3,536			418,487		43
	-211,969		812,128		44
94,301	-211,969		233,728,257		45
3,767,151	-248,015	-1,200	572,000,369		46

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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
		1,200	362,682		48
					49
339,167		-451,217	62,569,455		50
			4,692,263		51
194,311			76,420,961		52
169,838			66,885,953		53
					54
			80,637		55
					56
					57
703,316		-450,017	211,011,951		58
					59
			960,533		60
					61
587,924		412,602	50,069,965		62
					63
80,105			56,188,170		64
161,104		-7,200	43,138,261		65
		-10,879			66
209,566			54,263,039		67
483,255		56,694	59,178,214		68
40,932			40,185,029		69
1,354,863			29,570,322		70
126,267			3,775,523		71
					72
110,069			4,341,585		73
					74
3,154,085		451,217	341,670,641		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			1,434,176		86
150,042			29,292,294		87
361,941			7,898,556		88
1,601,291		-52,206	26,087,253		89
546					90
235,053		-29,519	4,052,530		91
126,457			249,167		92
59,735		81,725	553,466		93
137,929			5,798,061		94
					95
2,672,994			75,365,503		96
					97
					98
2,672,994			75,365,503		99
10,897,695	-248,015		1,203,969,941		100
					101
					102
					103
10,897,695	-248,015		1,203,969,941		104

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ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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38					
39					
40					
41					
42					
43					
44					
45					
46					
47	TOTAL				

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Various			29,656
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Various			
23				
24				
25				
26				
27				
28				
29				
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:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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 $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Belcourt, ND - Build new substation	152,554
2	Belcourt, ND - Repole transmission line	180,028
3	Bottineau, ND - Build new substation	103,698
4	Degraff, ND - Construct substation	152,775
5	Canby, MN - Rebuild transmission line	438,487
6	Big Stone City, SD - Construct new power plant	11,089,557
7	Morris, MN - Rebuild substation	115,665
8	Bemidji, MN - Grand Rapids, MN - Construct transmission line	834,533
9	Fargo, ND - St. Cloud, MN - Construct transmission line	792,037
10	Brookings, SD - SE Twin Cities - Construct transmission line	454,730
11	Crookston, MN - Install circuit switcher	282,448
12	Beulah, ND - Replace boiler reheat outlet section	1,170,885
13	Beulah, ND - Upgrade HP-IP turbine rotor	1,947,527
14	Fergus Falls, MN - Hoot Lake Plant - tools and equipment	100,080
15	System wide - Cyber security implementation	355,166
16	Dawson, MN - Uprate 115kv substation	340,595
17	Big Stone City, SD - Transmission line uprate/construction	320,714
18	System wide - Customer Service Center security additions	424,119
19	Sanborn, ND - Valley City, ND - Transmission line reroute	159,386
20	Big Stone City, SD - Land purchase	185,118
21	Fergus Falls, MN - Upgrade boiler control system	534,848
22	Crookston, MN - Rebuild 115kv substation	622,969
23	Spiritwood, ND - 115kv ring bus project	882,541
24	Fergus Falls, MN - Upgrade phone system	147,215
25	System wide - Personal computer replacements	313,665
26	Fergus Falls, MN - Storage area network expansion	134,017
27	Luverne, ND - Construct wind farm	889,725
28	Miscellaneous project under $100,000	2,421,585
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	25,546,667

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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	443,528,519	443,528,519		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	29,789,956	29,789,956		
4	(403.1) Depreciation Expense for Asset Retirement Costs	27,372	27,372		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,255,487	1,255,487		
7	Other Clearing Accounts	109,586	109,586		
8	Other Accounts (Specify, details in footnote):	226,862	226,862		
9	Other	-34,053	-34,053		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	31,375,210	31,375,210		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	10,294,342	10,294,342		
13	Cost of Removal	2,072,043	2,072,043		
14	Salvage (Credit)	1,649,980	1,649,980		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	10,716,405	10,716,405		
16	Other Debit or Cr. Items (Describe, details in footnote):	649,369	649,369		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	464,836,693	464,836,693		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	193,433,940	193,433,940		
21	Nuclear Production				
22	Hydraulic Production-Conventional	1,862,498	1,862,498		
23	Hydraulic Production-Pumped Storage				
24	Other Production	16,474,992	16,474,992		
25	Transmission	80,829,777	80,829,777		
26	Distribution	141,582,768	141,582,768		
27	Regional Transmission and Market Operation				
28	General	30,652,718	30,652,718		
29	TOTAL (Enter Total of lines 20 thru 28)	464,836,693	464,836,693		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) __ A Resubmission	12/31/2008	2008/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.: 8 Column: c

Transferred to a regulatory liability for the portion of depreciation accrued for future removeal cost on assets that are subject to asset retirement obligation (ARO) accounting.

Schedule Page: 219 Line No.: 9 Column: c

Adjusted ARO Accumulated Provision for Depreciation due to new estimates.

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

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

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

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	Otter Tail Energy Services Company			
2	Capital Stock			10
3	Additional paid in capital			4,452,294
4	Earnings (loss) since acquisition			-4,266,382
5				
6	Equity in subsidiary earnings			
7				
8				
9	Varistar			
10	Additional Paid in Capital			149,335,360
11	Advance (open stock)			34,720,516
12	Earnings (Loss) since acquisition			159,880,411
13				
14	Equity in subsidiary earnings			
15				
16				
17	Otter Tail Assurance			
18	Additional Paid in Capital			1,486,167
19	Earnings (Loss) since acquisition			575,145
20				
21	Equity in subsidiary earnings			
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 $ 198,421,487		TOTAL	346,183,521

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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 form investments, including such revenues form 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
		10		2
		4,452,294		3
		-4,671,818		4
				5
-405,436				6
				7
				8
				9
		192,548,812		10
		22,203,081		11
		165,418,935		12
				13
13,009,957				14
				15
				16
				17
		1,420,371		18
		964,194		19
				20
389,049				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
12,993,570		382,335,879		42

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) __ A Resubmission	12/31/2008	2008/Q4

FOOTNOTE DATA

Schedule Page: 224 Line No.: 12 Column: g

Includes the following 2008 changes, in addition to 2008 earnings:

	2007	2008
Distributions to parent	($6,956,028)	($7,471,433)

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	8,798,580	7,613,394	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)	3,855,189	4,373,508	Production
8	Transmission Plant (Estimated)	3,569,715	3,974,667	Various
9	Distribution Plant (Estimated)	6,078,164	6,767,676	Various
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	271,969	285,702	Fleet Service
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	13,775,037	15,401,553	
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)	22,573,617	23,014,947	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) __ A Resubmission	12/31/2008	2008/Q4

FOOTNOTE DATA

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

Consists of parts inventory at the Fleet Service Department.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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.	Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2009 No. (d)	2009 Amt. (e)
1	Balance-Beginning of Year	32,581.00		16,276.00	
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	14,244.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	18,337.00		16,276.00	
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	203.41		203.41	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	203.41			
40	Balance-End of Year			203.41	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	203.41	79,318		
45	Gains	203.41	79,318		
46	Losses				

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Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors 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.

2010 No. (f)	2010 Amt. (g)	2011 No. (h)	2011 Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)	Line No.
14,054.00		14,054.00		365,404.00		442,369.00		1
								2
								3
				14,054.00		14,054.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						14,244.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
14,054.00		14,054.00		379,458.00		442,179.00		29
								30
								31
								32
								33
								34
								35
202.97		202.97		9,945.30		10,758.06		36
				405.93		405.93		37
								38
				202.96		406.37		39
202.97		202.97		10,148.27		10,757.62		40
								41
								42
								43
				202.96	27,634	406.37	106,952	44
				202.96	27,634	406.37	106,952	45
								46

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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 Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
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12						
13						
14						
15						
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17						
18						
19						
20	TOTAL					

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Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/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 Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
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						
47						
48						
49	TOTAL					

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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	Big Stone II Interconnect Facility	6,240	417.1	9,684	417
23	Pillsbury Wind Interconnection	8,166	456	9,159	456
24	Burr Wind Interconnect Facility	9,321	456	9,658	456
25	Morris Wind Interconnect Facility	48,816	456	48,988	456
26	Pillsbury Wind Interconnect Fac	3,182	456	3,506	456
27	Tamarac Wind Interconnect Facility	28,126	456	28,143	456
28	Toronto Wind Interconnect Facility	81,815	456	82,652	456
29	Veblen Wind Interconnect Facility	55,404	456	55,600	456
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 $50,000 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 Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Deferred Income Tax Adjustments					
2	Due to SFAS109 on:					
3	Property Related Items	8,426,654		282	1,426,456	7,000,198
4	Non Property Related Items	306,160		190	212,564	93,596
5						
6						
7	Asset Retirement Obligation Capitalized					
8	Hoot Lake Plant	203,782	452,114			655,896
9	Big Stone Plant	11,288	119,386			130,674
10	Coyote Station	129,945	467,844			597,789
11	Wind Generation		161,227	407.4	108,680	52,547
12	Derivatives-Marked to Market Losses	770,712	2,911,023	244	2,519,414	1,162,321
13						
14	Regulatory Assets: MISO Costs Deferred	854,550		555	328,190	526,360
15	Regulatory Assets: MISO Refund	575,781	247,386			823,167
16						
17	SFAS 158 - Postretirement Medical Benefits	524,364	412,560	228.3	936,924	
18						
19	Regluatory Assets - ESSRP	5,275,630		228.3	740,588	4,535,042
20						
21	Regulatory Assets - Pension	21,132,892	40,812,890	228.3	1,990,358	59,955,424
22						
23	Regulatory Assets - Rate Case Exp Deferral		1,456,884			1,456,884
24						
25	Regulatory Assets - Rider Recovery - MN		6,626,552	407.3	3,582,011	3,044,541
26						
27	Regulatory Assets - Rider Recovery - ND		2,076,478		67,453	2,009,025
28						
29						
30						
31						
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41						
42						
43						
44	TOTAL	38,211,758	55,744,344		11,912,638	82,043,464

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) __ A Resubmission	12/31/2008	2008/Q4

FOOTNOTE DATA

Schedule Page: 232   Line No.: 27   Column: d

Accounts 440, 442, and 445 were debited.

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MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $50,000, 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 Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Conservation Improvement					
2	Programs - MN	490,714	2,366,111	908	2,591,769	265,056
3	Energy Efficiency					
4	Program - SD	27,488	46,268	908	63,680	10,076
5	Conservation Improvement					
6	Programs - ND		4,550			4,550
7	Deferred Cost - Big Stone					
8	Plant Acquisition					
9	(Amort. period 22-1/2 years)					
10	North Dakota	98,299		406	40,675	57,624
11	South Dakota	8,877		406	3,675	5,202
12						
13						
14						
15						
16						
17						
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44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	625,378				342,508

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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 Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Property Insurance Reserve		
3	Workman's Compensation Reserve	155,997	190,317
4	Medical Insurance Reserve		
5	Injuries and Damages Reserve	147,830	176,757
6	See Note Below	54,248,027	83,454,018
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	54,551,854	83,821,092
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)	54,551,854	83,821,092

Notes

NOTE: Continued From Above

Post Retirement Benefits	13,436,690	14,578,112
Executive Supplemental Pension	6,770,086	7,432,503
Reserve for Bad Debts	229,568	272,867
Accrued Vacation Pay	1,257,804	1,320,417
Capitalized Int. on Construction	2,314,613	3,127,268
Post Employment Benefits	1,121,752	1,175,066
Corporate Insurance Reserve	(69,784)	(108,734)
Nonqualified Retirement Savings	4,009,438	3,412,608
Deferred Settlement	25,526	0
Gain From Breck Sale	231,087	231,087
Reserve for Loan Pools	89,707	75,552
Gain on Reacquired Bonds	47	14
Capitalized A & G	5,186,812	5,633,023
Customer Rebates Capitalized	44,207	73,321
Asbestos Removal Costs Capitalized	13,218	10,855
Stock Incentives	320,318	594,735
Stock Options	11,378	(11,377)
Mapleton Land	27,982	31,061
CIAC Capitalized	305,815	282,878
Big Stone II Land	23,539	23,539
Otter Tail Assurance, LTD Gains/Losses	(14,467)	11,851
Medicare Part D	174,974	216,380
Executive Stock Incentive Plan	1,211,897	1,282,242
Affordable Housing	293,545	214,875
Charitable Contributions	0	205,955
Severance Settlement	0	97,500
Property Taxes	0	614,879
RSG Contingent Liability	0	211,770
ND NOL Carryforward	0	1,643,389
Wind Energy Income Tax Credits-ND	12,988,625	35,902,250
SFAS 109 Unamortized ITC	4,504,984	4,946,257
SFAS 109 Recognition of Regulatory Assets (Liab.)	(261,334)	(48,125)
	----------	----------
	54,248,027	83,454,018

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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 Over the Counter	50,000,000	5.00	
3	(National Market System)			
4				
5	TOTAL_COMMON	50,000,000		
6				
7	Account 204 (Stated Value)			
8	Cumulative Preferred	1,500,000		
9	$3.60 Dividend - No Exchange		100.00	102.25
10	$4.40 Dividend - No Exchange		100.00	102.00
11	$4.65 Dividend - No Exchange		100.00	101.50
12	$6.75 Dividend - No Exchange		100.00	101.69
13	Preference Shares	1,000,000		
14				
15	TOTAL_PREFERRED	2,500,000		
16				
17				
18				
19				
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CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
35,384,620	176,923,100					2
						3
						4
35,384,620	176,923,100					5
						6
						7
						8
60,000	6,000,000					9
25,000	2,500,000					10
30,000	3,000,000					11
40,000	4,000,000					12
						13
						14
155,000	15,500,000					15
						16
						17
						18
						19
						20
						21
						22
						23
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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	Tax benefit from stock options.	4,977,945
2	Executive stock incentive plan performance award.	4,115,340
3	Employee stock purchase plan expense	130,002
4	Stock option expense	361,872
5	Restricted stock units	897,707
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
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26		
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32		
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34		
35		
36		
37		
38		
39		
40	TOTAL	10,482,866

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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	9,754,778
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13	Cumulative Preferred Shares	
14	$6.75 Series	86,017
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	9,840,795

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 12/31/2008	2008/Q4

FOOTNOTE DATA

Schedule Page: 254 Line No.: 1 Column: a

In September 2008 the Company completed a public offering of 5,175,000 common shares under its universal shelf registration statement filed with the Securities and Exchange Commission, including 675,000 common shares issued pursuant to the full exercise of the underwriters' overallotment option. The public offering price was $30 per share. Net proceeds from the sale of the common shares after deducting underwriting discounts and commissions and offering expenses were $148.8 million.

Schedule Page: 254 Line No.: 1 Column: a

Footnote Linked. See note on 254, Row: 1, col/item:

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	2011 Series 6.63% Senior Notes	90,000,000	768,252
3	2012 Variable Series Pollution Control	10,400,000	142,703
4	2017 Series Pollution Control Refund-BSP	5,185,000	296,372
5	2022 Series Pollution Control Refund-CYT	20,790,000	1,232,035
6	Senior Unsecured Notes 6.47%, Series D	50,000,000	340,186
7			
8	Senior Unsecured Notes 6.37%, Series C	42,000,000	285,773
9			
10	Senior Unsecured Notes 6.15%, Series B	30,000,000	204,049
11	Senior Unsecured Notes 5.95%, Series A	33,000,000	224,506
12	Senior Unsecured Notes 5.778%	50,000,000	365,796
13	Account 222 - Reacquired Bonds - None		
14	Account 224 - Other Long - Term Debt		
15	Lombard US Equipment Finance	16,300,000	81,500
16			
17			
18	Instruction 9 - See Footnote		
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	347,675,000	3,941,172

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

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
12/27/01	12/01/11	01/01/02	12/01/11	90,000,000	5,967,000	2
12/15/93	12/01/12	12/01/93	12/01/12	10,400,000	419,774	3
09/26/01	09/01/17	10/01/01	09/01/17	5,165,000	240,792	4
09/26/01	09/01/22	10/01/01	09/01/22	20,625,000	1,002,899	5
08/20/07 &	08/20/37	08/20/07	08/20/37	50,000,000	3,235,000	6
10/01/07						7
08/20/07 &	08/20/27	08/20/07	08/20/27	42,000,000	2,675,400	8
10/01/07						9
10/01/07	08/20/22	10/01/07	08/20/22	30,000,000	1,845,000	10
10/01/07	08/20/17	10/01/07	08/20/17	33,000,000	1,963,500	11
12/14/07	11/30/17	12/14/07	11/30/17	50,000,000	2,889,000	12
						13
						14
09/24/03	10/02/10	09/30/03	09/30/10	4,657,140	373,852	15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				335,847,140	20,612,217	33

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) __ A Resubmission	12/31/2008	2008/Q4

FOOTNOTE DATA

Schedule Page: 256 Line No.: 15 Column: a

Instruction 9 - Unamortized debt expense, premium and discount are adjusted annually to reflect debt retired through sinking fund operations. Unamortized debt expense remaining on bonds retired early are transferred to Account 189 and amortized over remaining life of the bonds.

Schedule Page: 256 Line No.: 18 Column: a

Instruction 9 - Unamortized debt expense, premium and discount are adjusted annually to reflect debt retired through sinking fund operations. Unamortized debt expense remaining on bonds retired early are transferred to Account 189 and amortized over remaining life of the bonds.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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 field, 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)	35,124,611
2		
3		
4	Taxable Income Not Reported on Books	
5	Interest Capitalized on Construction	2,503,714
6	Net Gain from Property Retirements	665,162
7	Miscellaneous Taxable Items	9,000
8	Conservation Improvement Program - MN	215,582
9	Deductions Recorded on Books Not Deducted for Return	
10	Add Back Federal Income Taxes (Includes Deferreds & ITC Adj.)	7,247,300
11	Provisions for Reserves	9,484,732
12	Miscellaneous Unallowed Deductions	14,472,121
13		
14	Income Recorded on Books Not Included in Return	
15	Tax Exempt Interest	9,036
16	Equity in Earnings of Subsidiaries	12,993,570
17	Wind Rider Revenue	5,053,565
18	Miscellaneous Income Not Taxable	5,015,077
19	Deductions on Return Not Charged Against Book Income	
20	Excess Tax Depreciation Over Book Depreciation	100,790,273
21	Removal Costs	1,750,194
22	Charges to Reserves	4,624,920
23	Capital Loss Carry Forward	
24	Leveraged ESOP Deduction	1,891,010
25	Early Bond Redemption	
26	Miscellaneous Other Dedutions	2,669,823
27	Federal Tax Net Income	-65,075,246
28	Show Computation of Tax:	
29	Federal Tax (Line 27 X 35%)	-22,776,336
30	Tax (Credits) and Adjustments	-2,557,986
31	Prior Period Adjustments	-1,749,772
32		
33	Total Federal Income Tax	-27,084,094
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	See Footnote	
44		

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) 12/31/2008	2008/Q4

FOOTNOTE DATA

Schedule Page: 261 Line No.: 43 Column: a

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

Otter Tail Corporation is a member of an affiliated group which will file a consolidatd Federal Income Tax Return for the year 2008. The other members of the affiliated group and their respective federal income tax provisions are as follows:

1	Varistar Corporation	(648,974)
2	DMI Industries, Inc.	2,162,153
3	Aerial Contractors, Inc.	1,027,419
4	Moorhead Electric, Inc.	(262,188)
5	DMS Health Technologies, Inc.	173,752
6	DMS Imaging, Inc.	(1,122,088)
7	BTD Manufacturing, Inc.	2,593,240
8	Northern Pipe Products, Inc.	310,461
9	Otter Tail Energy Services Company	(254,739)
10	E. W. Wylie Corporation	(328,735)
11	Vinyltech Corporation	8,583
12	T. O. Plastics, Inc.	469,677
13	ShoreMaster, Inc.	(2,503,344)
14	Galva Foam Marine Industries, Inc.	(60,687)
15	Otter Tail Assurance Limited	225,308
16	Midwest Construction Services, Inc.	(104,085)
17	Overland Mechanical Services, Inc.	19,684
18	AC Equipment, Inc.	(1,410)
19	Foley Company	1,519,593
20	Lynk3 Technologies, Inc.	(57,521)
21	Ventus Energy Systems, Inc.	634,862
22	Idaho-Pacific Corporation	54,739
23	Idaho-Pacific Colorado Corporation	955,802
24	Shoreline Industries, Inc.	11,869
25	Aviva Sports, Inc.	(558,308)
26	Miller Welding & Iron Works, Inc.	(237,570)
	Total	4,027,493

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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	FEDERAL					
2	Income	2,899,964		1,243,562	-99,527	
3	Unemployment	1,027		53,282	53,087	
4	FICA	1		4,604,712	4,604,712	
5						
6	MINNESOTA					
7	Property	4,904,999		4,404,584	4,759,584	
8	Income	803,980		-360,641	792,936	
9	Unemployment	2,399		84,186	83,715	
10						
11	NORTH DAKOTA					
12	Property	2,332,547		2,574,783	2,407,332	
13	Income	-695,067		-2,482,697	-241,085	
14	Unemployment	588		12,310	12,582	
15	Foreign Corporation					
16	Coal Conversion	187,486		758,382	764,192	
17						
18	SOUTH DAKOTA					
19	Property	1,600,001		1,256,690	1,356,690	
20	Unemployment					
21	Foreign Corporation					
22						
23	OTHER STATES					
24	Income	-309,997		874,471	960,049	
25	Railcar	42,969		76,657	85,166	
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	11,770,897		13,100,281	15,539,433	

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
4,243,053		-23,679,888		-1,457,845	26,381,295	2
1,222					53,282	3
1					4,604,712	4
						5
						6
4,549,999		4,404,584				7
-349,597		146,813			-507,454	8
2,870					84,186	9
						10
						11
2,499,998		2,527,404			47,379	12
-2,936,679		-2,464,883			-17,814	13
316					12,310	14
						15
181,676		758,382				16
						17
						18
1,500,001		1,256,690				19
						20
						21
						22
						23
-395,575					874,471	24
34,460					76,657	25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
9,331,745		-17,050,898		-1,457,845	31,609,024	41

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

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

Acount 409.2 ($2,903,811): Account 409.2 ($82,860); Account 123.1 $6,185,251; Account 228.4 $23,182,715

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

Account 184

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

Account 184

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

Account 409.2 ($545,205); Account 123.1 $37,751

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

Account 184

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

Account 408.2 $1,861; Account 921 $45,518

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

Account 409.2 ($309,308); Account 123.1 $291,494

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

Account 184

Schedule Page: 262 Line No.: 24 Column: l

Account 409.2 $4,904; Account 123.1 $869,567

Schedule Page: 262 Line No.: 25 Column: l

Account 151

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%	9,717,500	190	19,244,050	411.4	592,096	
3	4%						
4	7%						
5	10%	7,044,005				1,125,759	
6							
7							
8	TOTAL	16,761,505		19,244,050		1,717,855	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
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48							

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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
28,369,454	25 yrs		2
			3
			4
5,918,246	33-1/3 yrs		5
			6
			7
34,287,700			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
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			45
			46
			47
			48

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

Schedule Page: 266   Line No.: 5   Column: e

Account 411.4 was allocated $1,125,086 and Account 411.5 was allocated $673.

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OTHER DEFFERED 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 $10,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Prepaid Electric Revenue	171,439	456	22,664	179,824	328,599
2	Miscellaneous				20,171	20,171
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
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33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	171,439		22,664	199,995	348,770

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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 rating 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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits Account Credited (g)	Debits Amount (h)	Credits Account Debited (i)	Credits Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
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NOTES (Continued)

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	123,057,760	45,424,189	6,253,731
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	123,057,760	45,424,189	6,253,731
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	123,057,760	45,424,189	6,253,731
10	Classification of TOTAL			
11	Federal Income Tax	102,365,023	39,265,481	5,332,332
12	State Income Tax	20,692,737	6,158,708	921,399
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits: Account Credited (g)	Debits: Amount (h)	Credits: Account Debited (i)	Credits: Amount (j)	Balance at End of Year (k)	Line No.
							1
	140,013	182.3	1,426,457	190	6,726,502	167,388,250	2
							3
							4
	140,013		1,426,457		6,726,502	167,388,250	5
							6
							7
							8
	140,013		1,426,457		6,726,502	167,388,250	9
							10
	115,562		1,199,687		6,726,502	141,709,425	11
	24,451		226,770			25,678,825	12
							13

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) __ A Resubmission	12/31/2008	2008/Q4

FOOTNOTE DATA

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

Adjustment due to SFAS 109.

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

Adjustment due to Deferred Tax Liability - Wind.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

ACCUMULATED DEFFERED 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)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Accum. Deferred Income Tax			
4	Other Utility Operations	1,445,511	3,320,167	1,173,817
5				
6	Accum. Deferred Income Tax			
7	Nonutility & Other	1,347,625		
8				
9	TOTAL Electric (Total of lines 3 thru 8)	2,793,136	3,320,167	1,173,817
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)	2,793,136	3,320,167	1,173,817
20	Classification of TOTAL			
21	Federal Income Tax	982,603	2,792,345	981,637
22	State Income Tax	1,810,533	527,822	192,180
23	Local Income Tax			

NOTES

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

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

CHANGES DURING YEAR		ADJUSTMENTS						
		Debits		Credits				
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
		See note	39,818,472	See note	39,024,030	2,797,419	4
							5
							6
828,488	1,174,654					1,001,459	7
							8
828,488	1,174,654		39,818,472		39,024,030	3,798,878	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
828,488	1,174,654		39,818,472		39,024,030	3,798,878	19
							20
696,779	987,279		33,488,356		32,820,210	1,834,665	21
131,709	187,375		6,330,116		6,203,820	1,964,213	22
							23

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) _ A Resubmission	12/31/2008	2008/Q4

FOOTNOTE DATA

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

Adjustments due to SFAS 109. Credits to Account 228.3 - $38,984,742; and Account 254 - $833,730.

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

Debits to Account 219 - $1,356,920; Account 182.3 - $37,557,580; and Account 228.4 - $109,530.

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

The asset retirement obligations for Hoot Lake Plant, Big Stone Plant, and Coyote Station were reclassified to account 254 in the 1st quarter of 2007.

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

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 $50,000 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 Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Deferred Income Tax Adjustments Due to	4,501,680	190	551,475	992,748	4,942,953
2	SFAS 109					
3						
4						
5	Minnesota Portion of Gain on Sale of Wahpeton	144,984	407.4	5,576		139,408
6	Division Office (Amortization period: 34 years)					
7						
8	Regulatory Liabilities - Derivatives	270,872		1,000,184	729,312	
9						
10	Hoot Lake Plant - Asset Retirement Obligation	3,164,568	108	9,955	60,270	3,214,883
11						
12	Big Stone Plant - Asset Retirement Obligation	6,126,517	108	205,134		5,921,383
13						
14	Coyote Station - Asset Retirement Obligation	3,026,401	108	72,043		2,954,358
15						
16	Qualified Pension Plan				833,729	833,729
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	17,235,022		1,844,367	2,616,059	18,006,714

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) __ A Resubmission	12/31/2008	2008/Q4

FOOTNOTE DATA

Schedule Page: 278 Line No.: 8 Column: c

$757,708 was credited to Account 175 and $242,476 was credited to Account 182.3.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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.

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	97,567,111	92,254,111
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	115,499,407	105,786,364
5	Large (or Ind.) (See Instr. 4)	72,686,119	74,821,602
6	(444) Public Street and Highway Lighting	3,063,290	2,868,359
7	(445) Other Sales to Public Authorities	2,531,032	2,461,466
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	291,346,959	278,191,902
11	(447) Sales for Resale	23,708,437	20,345,040
12	TOTAL Sales of Electricity	315,055,396	298,536,942
13	(Less) (449.1) Provision for Rate Refunds	3,715,982	1,297,930
14	TOTAL Revenues Net of Prov. for Refunds	311,339,414	297,239,012
15	Other Operating Revenues		
16	(450) Forfeited Discounts	594,458	545,326
17	(451) Miscellaneous Service Revenues	338,533	349,770
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	649,983	635,191
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	11,613,963	10,701,451
22	(456.1) Revenues from Transmission of Electricity of Others	442,793	433,024
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	13,639,730	12,664,762
27	TOTAL Electric Operating Revenues	324,979,144	309,903,774

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ELECTRIC OPERATING REVENUES (Account 400)

5. 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.)
6. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
7. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
8. 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
1,257,641	1,218,026	101,675	101,704	2
				3
1,558,950	1,518,825	26,529	26,422	4
1,357,006	1,318,059	51	51	5
27,121	27,078	415	406	6
41,189	41,843	611	592	7
				8
				9
4,241,907	4,123,831	129,281	129,175	10
4,729,086	3,543,401			11
8,970,993	7,667,232	129,281	129,175	12
				13
8,970,993	7,667,232	129,281	129,175	14

Line 12, column (b) includes $ -5,381,089 of unbilled revenues.

Line 12, column (d) includes 26,465 MWH relating to unbilled revenues

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FOOTNOTE DATA

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

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

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

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

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Not applicable.				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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22					
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25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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	R-01	865,596	78,279,418	94,816	9,129	0.0904
4						
5	Residential Service (Ctrl Demand)					
6	R-03	161,953	10,882,126	6,414	25,250	0.0672
7						
8	Water Heating (Controlled)					
9	R-91	47,638	2,922,527	18,458	2,581	0.0613
10				-18,458		
11	Controlled Service					
12	I-01,02,03	167,177	6,241,268	10,365	16,129	0.0373
13				-10,365		
14	Fixed Time of Delivery Service					
15	I-04	2,045	70,299	165	12,394	0.0344
16				-165		
17	Outdoor lighting-energy only					
18	M-41	66	4,683	6	11,000	0.0710
19				-6		
20	Area, Flood & Sign Lighting					
21	M-42	4,293	477,970	5,530	776	0.1113
22				-5,530		
23	Small power producer rider					
24	P-01	-75	45	2	-37,500	-0.0006
25				-2		
26	SUBTOTAL Billed	1,248,693	98,878,336	101,230	12,335	0.0792
27	Unbilled Rev (See Instr. 6)	8,949	-1,311,225			-0.1465
28	TOTAL - 440	1,257,642	97,567,111	101,230	12,424	0.0776
29						
30	Column D Lines 9, 12, 15,					
31	18, 21 & 24					
32	Customers are also served under					
33	other residential service.					
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	4,215,442	296,728,048	130,281	32,357	0.0704
42	Total Unbilled Rev.(See Instr. 6)	26,465	-5,381,089	0	0	-0.2033
43	TOTAL	4,241,907	291,346,959	130,281	32,560	0.0687

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2	Commercial & Industrial-442					
3	General Service					
4	G-01	758,111	68,916,552	23,541	32,204	0.0909
5						
6	General Service (Ctrl Demand)					
7	G-02	6,742	453,553	61	110,525	0.0673
8						
9	Electric Climate Control					
10	G-93	50,197	3,844,666	573	87,604	0.0766
11						
12	Farm Service					
13	F-61	61,662	4,582,415	2,750	22,423	0.0743
14						
15	Large Commercial Service					
16	C-02	1,159,518	72,596,123	574	2,020,066	0.0626
17						
18	Large Com Srv (Real Time Pricng)					
19	C-03	58,797	3,031,688	1	58,797,000	0.0516
20						
21	Large Gen. Srv. (Off Peak Rider)					
22	C-04	28,035	1,838,405	9	3,115,000	0.0656
23						
24	Large Gen. Srv. (Time of Use)					
25	C-09	427,799	23,082,846	18	23,766,611	0.0540
26						
27	Large Gen. Srv. Rider					
28	C-12	76,876	3,094,671	7	10,982,286	0.0403
29						
30	Water heating (controlled)					
31	R-91	2,190	130,992	618	3,544	0.0598
32				-618		
33						
34						
35						
36	Column D Line 30					
37	Customers are also served					
38	under other commercial service.					
39						
40						
41	TOTAL Billed	4,215,442	296,728,048	130,281	32,357	0.0704
42	Total Unbilled Rev.(See Instr. 6)	26,465	-5,381,089	0	0	-0.2033
43	TOTAL	4,241,907	291,346,959	130,281	32,560	0.0687

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3	Commercial and industrial - cntd					
4	Controlled service					
5	I-01, 02, 03	188,904	5,901,579	3,505	53,896	0.0312
6				-3,505		
7	Fixed time of delivery service					
8	I-04	16,246	474,216	366	44,388	0.0292
9				-366		
10	Bulk interruptible service					
11	I-06	15,192	675,183	1	15,192,000	0.0444
12						
13	Irrigation service					
14	M-03	5,884	349,610	219	26,868	0.0594
15						
16	Commercial time of use					
17	M-04	23,323	1,383,242	125	186,584	0.0593
18						
19	Outdoor lighting-energy only					
20	M-41	486	36,224	45	10,800	0.0745
21				-45		
22	Area, flood, and sign lighting					
23	M-42, M-51	15,683	1,676,489	5,776	2,715	0.1069
24				-5,776		
25	Standby service					
26	P-13	149	22,204	3	49,667	0.1490
27						
28	Residential service					
29	R-01	266	21,402	10	26,600	0.0805
30						
31	Residential service (ctrl demand)					
32	R-03	2,623	164,484	76	34,513	0.0627
33						
34	Small power producer rider					
35	P-01		72	4		
36				-4		
37	Column D, lines 3,6,18,21,& 33					
38	Customers are also served under					
39	other commerical service.					
40						
41	TOTAL Billed	4,215,442	296,728,048	130,281	32,357	0.0704
42	Total Unbilled Rev.(See Instr. 6)	26,465	-5,381,089	0	0	-0.2033
43	TOTAL	4,241,907	291,346,959	130,281	32,560	0.0687

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2	Commercial and industrial - conti					
3	Small power producer rider					
4	P-09	-8	35	3	-2,667	-0.0044
5				-3		
6	SUBTOTAL Billed	2,898,675	192,276,651	27,968	103,643	0.0663
7	Unbilled Rev (See Instr. 6)	17,280	-4,091,125			-0.2368
8	TOTAL - 442	2,915,955	188,185,526	27,968	104,260	0.0645
9						
10	Miscellaneous					
11	Streetlighting - 444					
12	Outdoor lighting-energy only					
13	M-41	3,939	281,780	156	25,250	0.0715
14				-156		
15	Area, flood, and sign lighting					
16	M-42, M-51	23,174	2,731,069	422	54,915	0.1179
17	Subtotal billed	27,113	3,012,849	422	64,249	0.1111
18	Unbilled Revenue	8	50,441			6.3051
19	TOTAL - 444	27,121	3,063,290	422	64,268	0.1129
20						
21	Other Public Authority-445	40,961	2,560,212	661	61,968	0.0625
22	Unbilled Revenue	228	-29,180			-0.1280
23	TOTAL - 445	41,189	2,531,032	661	62,313	0.0614
24						
25	Revenue from Fuel Adjustment					
26	Clause is reported in footnote.					
27						
28	Column D, Lines 3 & 12					
29	Customers are also served under					
30	other commercial service.					
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	4,215,442	296,728,048	130,281	32,357	0.0704
42	Total Unbilled Rev.(See Instr. 6)	26,465	-5,381,089	0	0	-0.2033
43	TOTAL	4,241,907	291,346,959	130,281	32,560	0.0687

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Schedule Page: 304.3 Line No.: 25 Column: a

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

Residential - 440	
R-01 Residential service	$ 8,845,342
R-03 Residential service (control demand)	2,287,978
R-91 Water heating (controlled)	446,706
I-03 Controlled service	154,964
M-41 Outdoor lighting - energy only	136
Total residential	11,735,126
Commercial and industrial - 442	
G-01 General service	8,062,693
G-02 General service (control demand)	104,191
G-93 Electric climate control	961,370
F-61 Farm service	526,031
C-02 Large commercial service	9,616,174
C-03 Large commercial service (real-time pricing)	359,052
C-04 Large general service (off-peak rider)	178,156
C-09 Large general service (time of use)	793,497
C-12 Large general service rider	243,630
I-03 Controlled service	342,983
M-03 Irrigation service	(6,800)
M-04 Commercial time of use	48,752
M-41 Outdoor lighting - energy only	909
R-01 Residential service	3,438
R-03 Residential service (control demand)	34,770
R-91 Water heating (controlled)	20,177
Total commercial and industrial	21,289,023
Miscellaneous	
Streetlighting - 444	
M-41 Outdoor lighting - energy only	8,485
Other pubic authority - 445	378,052
Total miscellaneous	386,537
Total	$ 33,410,686

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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 note 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 tong-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 Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	RQ SALES					
2	Badger, SD	RQ	144	.098	NA	NA
3	Newfolden, MN	RQ	174	.505	NA	NA
4	Nielsville, MN	RQ	175	.044	NA	NA
5	Shelly, MN	RQ	176	.192	NA	NA
6						
7						
8	NON-RQ SALES					
9	American Electric Power Service	OS	180	NA	NA	NA
10	AmerenUE	OS	180	NA	NA	NA
11	Black Hills Power and Light	OS	180	NA	NA	NA
12	Cargill Power Markets, LLC	OS	180	NA	NA	NA
13	Constellation Engy Commodities Grp Inc	OS	180	NA	NA	NA
14	DTE Energy Trading, Inc.	OS	180	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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SALES FOR RESALE (Account 447)

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 note 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:
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LF - for tong-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.
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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)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Fortis Energy Marketing and Trading	OS	180	NA	NA	NA
2	Great River Energy	OS	180	NA	NA	NA
3	High Sierra Power Marketing LLC	OS	180	NA	NA	NA
4	Integrys Energy Services Inc	OS	180	NA	NA	NA
5	Kansas City Power and Light	OS	180	NA	NA	NA
6	Lighthouse Energy Trading Company	OS	180	NA	NA	NA
7	Lincoln Electric System	OS	180	NA	NA	NA
8	Manitoba Hydro Electric Board	OS	180	NA	NA	NA
9	Minnesota Municipal Power Agency	OS	180	NA	NA	NA
10	Minnesota Power	OS	180	NA	NA	NA
11	Minnkota Power Cooperative	OS	180	NA	NA	NA
12	Minnkota Power Coop - Ashtabula Wind			NA	NA	NA
13	Missouri River Energy Services	OS	180	NA	NA	NA
14	Municipal Energy Agency of Nebraska	OS	180	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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).
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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.
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW) Average Monthly NCP Demand	Actual Demand (MW) Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Northern States Power Company	OS	180	NA	NA	NA
2	NorthPoint Energy Solutions Inc.	OS	180	NA	NA	NA
3	NorthWestern Energy	OS	180	NA	NA	NA
4	Omaha Public Power District	OS	180	NA	NA	NA
5	Public Service Company of Colorado	OS	180	NA	NA	NA
6	Rainbow Energy Marketing Corp	OS	180	NA	NA	NA
7	Sempra Energy Trading Corporation	OS	180	NA	NA	NA
8	Split Rock Energy	OS	180	NA	NA	NA
9	Tenaska Power Services Co.	OS	180	NA	NA	NA
10	The Energy Authority	OS	180	NA	NA	NA
11	Transalta Energy Marketing	OS	180	NA	NA	NA
12	Utilities Plus	OS	180	NA	NA	NA
13	WE Energies	OS	180	NA	NA	NA
14	Western Area Power Administration	OS	180	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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 note 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:
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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	Western Resources	OS	180	NA	NA	NA
2	Wisconsin Public Power Inc.	OS	180	NA	NA	NA
3	UBS Securities LLC	OS	180	NA	NA	NA
4	RBC Capital Markets Corporation	OS	180	NA	NA	NA
5	Midwest ISO Automatic Reserve Sharing	OS	181	NA	NA	NA
6	Midwest ISO Energy Market	OS	180	NA	NA	NA
7	Non-asset based sales	OS	181	NA	NA	NA
8						
9						
10						
11						
12						
13	See Footnote					
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

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,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
459	6,150	15,673	5,826	27,649	2
2,412	33,638	82,403	35,677	151,718	3
92	2,908	3,146	1,559	7,613	4
875	14,092	29,896	12,891	56,879	5
					6
					7
					8
123,200		6,694,880		6,694,880	9
800		-782		-782	10
10,165		616,240		616,240	11
280,600		16,786,080		16,786,080	12
713,875		15,739,024		15,739,024	13
198,150		2,713,621		2,713,621	14
3,838	56,788	131,118	55,953	243,859	
4,725,248	0	23,457,023	7,555	23,464,578	
4,729,086	**56,788**	**23,588,141**	**63,508**	**23,708,437**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
69,600		725,397		725,397	1
44,800		435,819		435,819	2
101,600		1,374,226		1,374,226	3
12,400		-44,981		-44,981	4
874		75,302		75,302	5
9,200		733,600		733,600	6
10,322		695,905		695,905	7
8,800		-14,517		-14,517	8
18,000		902,200		902,200	9
59,680		3,558,312		3,558,312	10
3,600		224,400		224,400	11
3,696		164,269		164,269	12
2,080		119,660		119,660	13
1		81		81	14
3,838	56,788	131,118	55,953	243,859	
4,725,248	0	23,457,023	7,555	23,464,578	
4,729,086	**56,788**	**23,588,141**	**63,508**	**23,708,437**	

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
712,350		7,453,949		7,453,949	1
11,112		461,842		461,842	2
			6,219	6,219	3
10,595		584,965		584,965	4
1,080		74,160		74,160	5
43,336		1,100,515		1,100,515	6
224,800		16,704,720		16,704,720	7
					8
135		9,450		9,450	9
177,999		12,917,585		12,917,585	10
					11
896		65,046		65,046	12
26,800		1,962,200		1,962,200	13
84,568		4,708,871		4,708,871	14
3,838	56,788	131,118	55,953	243,859	
4,725,248	0	23,457,023	7,555	23,464,578	
4,729,086	**56,788**	**23,588,141**	**63,508**	**23,708,437**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
23,600		254,055		254,055	1
			1,336	1,336	2
143,900		1,265,116		1,265,116	3
810,600		7,333,032		7,333,032	4
		70,767		70,767	5
1,463,294		45,257,037		45,257,037	6
-681,260		-128,265,023		-128,265,023	7
					8
					9
					10
					11
					12
					13
					14
3,838	56,788	131,118	55,953	243,859	
4,725,248	0	23,457,023	7,555	23,464,578	
4,729,086	**56,788**	**23,588,141**	**63,508**	**23,708,437**	

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

Lines 2 - 5 are fuel adjustment charges.

Schedule Page: 310.2 Line No.: 3 Column: j

Schedule B charge.

Schedule Page: 310.3 Line No.: 2 Column: j

Schedule B charge.

Schedule Page: 310.3 Line No.: 7 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.

Schedule Page: 310.3 Line No.: 13 Column: a

MAPP Transmission Service Charges for Non-RQ sales is $28,909.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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	1,541,216	1,394,608
5	(501) Fuel	67,354,090	55,008,518
6	(502) Steam Expenses	3,146,222	3,191,009
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,386,966	2,260,200
10	(506) Miscellaneous Steam Power Expenses	4,388,519	4,140,261
11	(507) Rents	9,811	3,216
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	78,826,824	65,997,812
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	717,396	695,172
16	(511) Maintenance of Structures	646,627	605,164
17	(512) Maintenance of Boiler Plant	6,280,633	5,918,965
18	(513) Maintenance of Electric Plant	2,935,656	687,113
19	(514) Maintenance of Miscellaneous Steam Plant	1,100,270	800,370
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	11,680,582	8,706,784
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	90,507,406	74,704,596
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	33,070	65,688
45	(536) Water for Power		
46	(537) Hydraulic Expenses	7,801	6,565
47	(538) Electric Expenses	34,145	52,478
48	(539) Miscellaneous Hydraulic Power Generation Expenses	156	3,558
49	(540) Rents	385	
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	75,557	128,289
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	1,216	280
54	(542) Maintenance of Structures	8,108	4,846
55	(543) Maintenance of Reservoirs, Dams, and Waterways	236,803	417,502
56	(544) Maintenance of Electric Plant	30,884	39,688
57	(545) Maintenance of Miscellaneous Hydraulic Plant	29,126	18,991
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	306,137	481,307
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	381,694	609,596

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Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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	66,149	37,444
63	(547) Fuel	5,191,639	6,236,150
64	(548) Generation Expenses	1,119,221	622,259
65	(549) Miscellaneous Other Power Generation Expenses	88,459	68,914
66	(550) Rents	109,158	3,647
67	TOTAL Operation (Enter Total of lines 62 thru 66)	6,574,626	6,968,414
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	13,920	48,987
70	(552) Maintenance of Structures	13,705	3,337
71	(553) Maintenance of Generating and Electric Plant	940,205	1,191,492
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	27,369	12,313
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	995,199	1,256,129
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	7,569,825	8,224,543
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	56,334,634	74,694,689
77	(556) System Control and Load Dispatching	309,643	259,924
78	(557) Other Expenses	1,883,395	1,847,801
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	58,527,672	76,802,414
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	156,986,597	160,341,149
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	423,941	511,139
84	(561) Load Dispatching		
85	(561.1) Load Dispatch-Reliability	68,854	48,028
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,631,747	2,398,686
87	(561.3) Load Dispatch-Transmission Service and Scheduling		19,089
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	378,217	325,934
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	168,764	160,433
94	(563) Overhead Lines Expenses	239,309	540,237
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	41,661	10,283
97	(566) Miscellaneous Transmission Expenses	1,095,095	1,018,264
98	(567) Rents	71,274	40,143
99	TOTAL Operation (Enter Total of lines 83 thru 98)	5,118,862	5,072,236
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	383,511	403,322
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	8,618	7,601
104	(569.2) Maintenance of Computer Software	876,117	561,311
105	(569.3) Maintenance of Communication Equipment	132,393	183,405
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,068,756	1,143,012
108	(571) Maintenance of Overhead Lines	1,864,421	1,630,625
109	(572) Maintenance of Underground Lines	1,230	308
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	4,335,046	3,929,584
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	9,453,908	9,001,820

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation	1,226,192	1,173,754
117	(575.3) Transmission Rights Market Facilitation	235,837	261,333
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)	1,462,029	1,435,087
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software	40,174	56,085
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)	40,174	56,085
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	1,502,203	1,491,172
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	397,506	522,846
135	(581) Load Dispatching	356,114	295,848
136	(582) Station Expenses	153,356	145,438
137	(583) Overhead Line Expenses	247,451	330,930
138	(584) Underground Line Expenses	1,173,207	1,099,905
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	1,022,451	1,000,585
141	(587) Customer Installations Expenses	354,144	327,862
142	(588) Miscellaneous Expenses	2,464,143	2,274,823
143	(589) Rents	343,226	240,965
144	TOTAL Operation (Enter Total of lines 134 thru 143)	6,511,598	6,239,202
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	805,567	813,410
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	677,918	832,021
149	(593) Maintenance of Overhead Lines	4,416,717	4,537,893
150	(594) Maintenance of Underground Lines	830,403	829,638
151	(595) Maintenance of Line Transformers		
152	(596) Maintenance of Street Lighting and Signal Systems	1,098,665	992,747
153	(597) Maintenance of Meters	440,213	441,438
154	(598) Maintenance of Miscellaneous Distribution Plant		
155	TOTAL Maintenance (Total of lines 146 thru 154)	8,269,483	8,447,147
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	14,781,081	14,686,349
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	164,509	192,629
160	(902) Meter Reading Expenses	4,545,580	4,569,617
161	(903) Customer Records and Collection Expenses	5,033,027	4,713,170
162	(904) Uncollectible Accounts	945,025	684,000
163	(905) Miscellaneous Customer Accounts Expenses	326,543	347,844
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	11,014,684	10,507,260

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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	708,791	727,164
168	(908) Customer Assistance Expenses	4,358,788	4,106,516
169	(909) Informational and Instructional Expenses	281,894	327,300
170	(910) Miscellaneous Customer Service and Informational Expenses	54,712	80,719
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	5,404,185	5,241,699
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	649,883	803,691
176	(913) Advertising Expenses	89,415	299,288
177	(916) Miscellaneous Sales Expenses	317,792	318,260
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	1,057,090	1,421,239
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	16,591,281	16,602,139
182	(921) Office Supplies and Expenses	4,767,718	4,649,145
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	1,467,767	1,595,302
185	(924) Property Insurance	1,523,294	974,518
186	(925) Injuries and Damages	1,783,852	1,646,497
187	(926) Employee Pensions and Benefits	1,905,237	914,010
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	3,493,762	1,931,771
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	903,894	615,095
192	(930.2) Miscellaneous General Expenses	609,869	680,508
193	(931) Rents	180,782	295,752
194	TOTAL Operation (Enter Total of lines 181 thru 193)	33,227,456	29,904,737
195	Maintenance		
196	(935) Maintenance of General Plant	2,317,681	2,724,986
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	35,545,137	32,629,723
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	235,744,885	235,320,411

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) __ A Resubmission	12/31/2008	2008/Q4

FOOTNOTE DATA

Schedule Page: 320 Line No.: 84 Column: b

$983,202 of the year-to-date expense recorded in Accounts 561 and 569 is designated as Account 561.BA expense.

Schedule Page: 320 Line No.: 84 Column: c

$1,001,213 of the year-to-date expense recorded in accounts 561 and 569 is designated as account 561.BA expense.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	AmerenUE	OS		NA	NA	NA
2	Black Hills Power and Light	OS		NA	NA	NA
3	Cargill Power Markets, LLC	OS		NA	NA	NA
4	Constellation Energy Commodities Group	OS		NA	NA	NA
5	DTE Energy Trading, Inc.	OS		25	NA	NA
6	Fortis Energy Marketing and Trading	OS		NA	NA	NA
7	Great River Energy	OS		NA	NA	NA
8	Great River Energy	SF		50	NA	NA
9	High Sierra Power Marketing, LLC	OS		NA	NA	NA
10	Integrys Energy Services Inc	OS		NA	NA	NA
11	Lighthouse Energy Trading Company, Inc	OS		NA	NA	NA
12	Manitoba Hydro Electric Board	SF		50	NA	NA
13	Manitoba Hydro Electric Board	OS		NA	NA	NA
14	Mid-American Energy Company	OS		NA	NA	NA
	Total					

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PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Minnesota Municipal Power Agency	OS		NA	NA	NA
2	Minnesota Power	OS		NA	NA	NA
3	Minnkota Power Cooperative	OS		NA	NA	NA
4	Missouri River Energy Services	OS		NA	NA	NA
5	Northern States Power Company	OS		NA	NA	NA
6	Northern States Power Company	SF		25	NA	NA
7	NorthPoint Energy Solutions Inc	OS		NA	NA	NA
8	Omaha Public Power District	OS		NA	NA	NA
9	Rainbow Energy Marketing Corp.	OS		NA	NA	NA
10	Sempra Energy Trading Corporation	OS		NA	NA	NA
11	The Energy Authority	OS		NA	NA	NA
12	Transalta Energy Marketing	OS		NA	NA	NA
13	Western Area Power Administration	OS		NA	NA	NA
14	Western Area Power Administration-WEC	OS		NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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.

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Western Resources	OS		NA	NA	NA
2	Wisconsin Public Power Inc	SF		35	NA	NA
3	Beltrami Electric Cooperative	RQ		NA	NA	NA
4	Nodak Rural Electric Cooperative	RQ		NA	NA	NA
5	P K M Electric Cooperative	RQ		NA	NA	NA
6	NorthWestern Energy - NLE	RQ		NA	NA	NA
7	Red Lake Rural Electric Cooperative	RQ		NA	NA	NA
8	Lake Region Rural Electric Cooperative	RQ		NA	NA	NA
9	Redwood Rural Electric Cooperative	RQ		NA	NA	NA
10	Cass County Electric Cooperative	RQ		NA	NA	NA
11	City of Perham	RQ		NA	NA	NA
12	Lac Qui Parle School	RQ		NA	NA	NA
13	Dakota Magic Casino	RQ		NA	NA	NA
14	State Auto Insurance	RQ		NA	NA	NA
	Total					

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PURCHASED POWER (Account 555)
(Including power exchanges)

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

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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.

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Kindred School	RQ		NA	NA	NA
2	Fleet Farm	RQ		NA	NA	NA
3	Valley Queen Cheese	OS		NA	NA	NA
4	Stevens Community Medical	OS		NA	NA	NA
5	City of Detroit Lakes	OS		NA	NA	NA
6	American Crystal Sugar	OS		NA	NA	NA
7	Energy Maintenance Service	OS		NA	NA	NA
8	Hendricks Wind 1	OS		NA	NA	NA
9	Borderline Wind	OS		NA	NA	NA
10	Univ. of MN - Morris	OS		NA	NA	NA
11	FPL Energy ND II, LLC	OS		NA	NA	NA
12	Langdon Wind, LLC	OS		NA	NA	NA
13	MN Co Generation	OS		NA	NA	NA
14	ND Co Generation	OS		NA	NA	NA
	Total					

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PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	ABN AMRO Inc / USB Securities LLC	OS		NA	NA	NA
2	RBC Capital Markets Corporation	OS		NA	NA	NA
3	Basin/CPEC/ER RLA Adjustment	OS		NA	NA	NA
4	MISO Transmission Service Charge	OS		NA	NA	NA
5	MAPP Transmission Service Charge	OS		NA	NA	NA
6	WAPA Schedule and Dispatch	OS		NA	NA	NA
7	Midwest ISO Energy market	OS		NA	NA	NA
8	Control Area Exchange - Net	OS		NA	NA	NA
9	Non-asset based cost of sales					
10						
11						
12						
13						
14						
	Total					

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (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 MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
1,600				7,482		7,482	1
2,398				126,120		126,120	2
115,230				8,377,470		8,377,470	3
703,075				9,537,484		9,537,484	4
129,600			15,000	1,400,596		1,415,596	5
44,000				642,048		642,048	6
81,810				791,108		791,108	7
			218,000			218,000	8
105,600				1,388,469		1,388,469	9
69,950				396,160		396,160	10
1,600				90,400		90,400	11
			1,618,800			1,618,800	12
567,908				20,412,762	-810,949	19,601,813	13
185,021				10,405,319		10,405,319	14
5,297,596			4,296,524	52,270,062	-231,952	56,334,634	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (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)	
400				22,086		22,086	1
50,560				2,844,056		2,844,056	2
17,888				282,691		282,691	3
6,580				185,010		185,010	4
334,440				4,615,204		4,615,204	5
			338,750			338,750	6
2,000				136,600		136,600	7
46,080				2,364,913	815	2,365,728	8
9,522				375,360		375,360	9
69,600				4,580,680		4,580,680	10
5,925				314,150		314,150	11
2,400				-9,673		-9,673	12
1,600				73,220	15,317	88,537	13
29,973				734,034		734,034	14
5,297,596			4,296,524	52,270,062	-231,952	56,334,634	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (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)	
52,000				64,065		64,065	1
			525,750			525,750	2
84,579			995,458	3,557,452	162,835	4,715,745	3
515			29,057	28,433		57,490	4
2,517			51,521	112,457		163,978	5
19,998			160,101	862,020		1,022,121	6
3,004			54,960	133,436		188,396	7
24				2,669		2,669	8
10				910		910	9
			18	391		409	10
			31,564			31,564	11
39				1,764		1,764	12
			35,492			35,492	13
			36,000			36,000	14
5,297,596			4,296,524	52,270,062	-231,952	56,334,634	

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 monnthly (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)	
			35,280			35,280	1
			17,624			17,624	2
			111,440			111,440	3
			20,520			20,520	4
978			1,189	1,468		2,657	5
166				1,656		1,656	6
141				4,521		4,521	7
2,456				110,506		110,506	8
1,346				40,378		40,378	9
1,142				49,139		49,139	10
60,610				1,812,251		1,812,251	11
69,559				2,727,051		2,727,051	12
34				4,201		4,201	13
229							14
5,297,596			4,296,524	52,270,062	-231,952	56,334,634	

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 monnthly (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)	
139,950				-470,964		-470,964	1
1,512,250				5,267,241		5,267,241	2
-147				-43,491		-43,491	3
					206,717	206,717	4
					168,467	168,467	5
					24,846	24,846	6
2,253,217				91,650,801		91,650,801	7
				-855,881		-855,881	8
-1,491,781				-122,886,161		-122,886,161	9
							10
							11
							12
							13
							14
5,297,596			4,296,524	52,270,062	-231,952	56,334,634	

Name of Respondent Otter Tail Corporation	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4

FOOTNOTE DATA

Schedule Page: 326 Line No.: 5 Column: a
Winter season through April 30, 2009.

Schedule Page: 326 Line No.: 8 Column: a
Winter season through March 31, 2009.

Schedule Page: 326 Line No.: 12 Column: a
Winter season through April 30, 2009.

Schedule Page: 326 Line No.: 13 Column: l
MHEB PAC Loss Credit.

Schedule Page: 326.1 Line No.: 6 Column: a
Winter season through May 31, 2009 and summer season throught November 30, 2009.

Schedule Page: 326.1 Line No.: 8 Column: l
Omaha Public Power District Transmission.

Schedule Page: 326.1 Line No.: 13 Column: l
Load Following charge.

Schedule Page: 326.2 Line No.: 2 Column: a
Winter season through May 31, 2009.

Schedule Page: 326.2 Line No.: 3 Column: l
Nomination charge.

Schedule Page: 326.4 Line No.: 4 Column: l
Transmission service charge.

Schedule Page: 326.4 Line No.: 5 Column: l
Transmission service charge.

Schedule Page: 326.4 Line No.: 6 Column: l
Scheduling/dispatch charge.

Schedule Page: 326.4 Line No.: 7 Column: a
Midwest ISO Energy Market

Schedule Page: 326.4 Line No.: 8 Column: a
Represents control area exchange as of December 31. These are inadvertant exchanges of electricity between utilities in the exchange area.

Schedule Page: 326.4 Line No.: 9 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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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 Classifi-cation (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	LFP
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	See Footnote			
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered 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 (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
4	(1)	Badger, SD		1,403	1,343	1
4	(1)	Newfolden, MN		3,007	2,810	2
4	(1)	Nielsville, MN		679	635	3
4	(1)	Shelly, MN		1,761	1,646	4
4	(1)	Fort Totten, ND		257	242	5
4	(1)	Grafton, ND		4,964	4,683	6
4	(1)	Devils Lake, ND		606	566	7
4	(1)	Bottineau, ND		1,138	1,064	8
4	(1)	Wahpeton, ND		8,859	8,318	9
4	(1)	Belcourt, ND		2,770	2,613	10
4	(1)	Oakes, ND		29	28	11
See Footnote	(1)	Various Interconnecs		225,954	211,172	12
		(1)		13,748		13
		(1)		-123,476		14
		(1)		-5,971		15
	See Footnote					16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**135,728**	**235,120**	

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
9,378			9,378	1
26,538			26,538	2
8,122			8,122	3
16,969			16,969	4
1,331			1,331	5
24,729			24,729	6
5,731			5,731	7
10,921			10,921	8
92,247			92,247	9
34,902			34,902	10
753			753	11
	211,172		211,172	12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
231,621	**211,172**	**0**	**442,793**	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) __ A Resubmission	12/31/2008	2008/Q4

FOOTNOTE DATA

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

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

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

Various companies
Miscellaneous losses - mwh received

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

(1) Various points of interconnect in the integrated system in column f, lines 1-12 and column g, lines 13-15.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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 Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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19					
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21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Otter Tail Power Co.	FNS					7,115	7,115
2	Omaha Public Power Dist	NF		50			3	3
3	Omaha Public Power Dist	SFP		100			153	153
4	Saskatchewan Power Corp	NF		270			227	227
5	Western Area Power Admn	NF		1,847			1,238	1,238
6	Western Area Power Admn	SFP		5			11	11
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL			2,272			8,747	8,747

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Otter Tail Corporation	(1) X An Original (2) __ A Resubmission	12/31/2008	2008/Q4

FOOTNOTE DATA

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

Charges 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 2008.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	45,873
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	54,451
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	122,740
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	24,546
6	Director fees and expenses	221,497
7		
8	Miscellaneous labor not provided for elsewhere	140,762
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
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21		
22		
23		
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28		
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43		
44		
45		
46	TOTAL	609,869

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition 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			622,466		622,466
2	Steam Production Plant	9,561,307	7,566			9,568,873
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	98,894				98,894
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	4,458,604	19,806			4,478,410
7	Transmission Plant	3,975,182				3,975,182
8	Distribution Plant	9,224,741				9,224,741
9	Regional Transmission and Market Operation					
10	General Plant	2,471,228				2,471,228
11	Common Plant-Electric					
12	TOTAL	29,789,956	27,372	622,466		30,439,794

B. Basis for Amortization Charges

The $622,466 is amortization of:

Miscellaneous Intangible Plan (303)
$574,582 for computer software with a 5-year service life at a 20% rate.

Franchises and Consents (302)
$47,884 for hydro plant licenses with a remaining life of 12.54 years at a 3.68% 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	4,673		-3.70	1.90	SQ	13.26
15	312	32,331		-3.70	3.69	SQ	13.26
16	314	16,878		-3.70	4.49	SQ	13.27
17	315	2,329		-3.70	2.36	SQ	13.26
18	316	983		-3.50	3.12	SQ	13.26
19							
20	Steam Production						
21	Hoot Lake Plant						
22	311 - Units 2,3	180		-9.10	1.18	SQ	10.35
23	312 - Units 2,3	7,400		-9.10	3.50	SQ	10.36
24	314 - Units 2,3	1,963		-9.10	2.67	SQ	10.36
25	315 - Units 2,3	36		-9.10	1.05	SQ	10.35
26	316 - Units 2,3	446		-9.00	6.17	SQ	10.36
27							
28	Steam Production						
29	Coyote Plant						
30	311	11,628		-1.60	2.13	SQ	18.05
31	312	35,642		-1.60	2.36	SQ	18.05
32	314	8,314		-1.60	2.62	SQ	18.05
33	315	3,074		-1.60	2.09	SQ	18.04
34	316	1,040		-1.40	3.37	SQ	18.06
35	STEAM PRODUCTION						
36	SUBTOTAL	126,917					
37							
38	Hydro Production -						
39	Hoot Lake Hydro						
40	331	-3			-0.25	SQ	14.22
41	332	-18			-0.51	SQ	14.21
42	333	49			3.32	SQ	14.23
43	334	12			2.34	SQ	14.23
44	Hydro Production -						
45	Wright Hydro						
46	331	8			2.85	SQ	14.22
47	332	51			1.83	SQ	14.21
48	333	153			4.70	SQ	14.23
49	334	135			5.19	SQ	14.23
50	335	24			3.03	SQ	14.23

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12							
13	Hydro Production -						
14	Pisgah Hydro						
15	331	5			2.71	SQ	14.22
16	332	34			2.19	SQ	14.21
17	333	139			6.12	SQ	14.23
18	334	88			5.58	SQ	14.23
19	335	11			3.58	SQ	14.23
20							
21	Hydro Production -						
22	Dayton Hollow Hydro						
23	331				1.45	SQ	14.22
24	332	90			2.00	SQ	14.21
25	333	144			7.39	SQ	14.23
26	334	64			3.39	SQ	14.23
27	335	3			2.11	SQ	14.23
28							
29	Hydro Production -						
30	Taplin Gorge Hydro						
31	331	3			0.57	SQ	14.22
32	332	83			1.59	SQ	14.21
33	333	8			3.73	SQ	14.23
34	334	4			3.09	SQ	14.23
35	335	26			2.94	SQ	14.23
36							
37	Hydro Production -						
38	Bemidji Hydro						
39	331	37			4.98	SQ	14.22
40	332	104			3.39	SQ	14.21
41	333	146			3.77	SQ	14.23
42	334	5			5.31	SQ	14.23
43	335	1			17.63	SQ	14.23
44	HYDRO PRODUCTION						
45	SUBTOTAL	1,406					
46							
47							
48							
49							
50							

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Other Production -						
13	Jamestown Peaking #1						
14	341	65			2.31	SQ	12.29
15	342	52			2.05	SQ	12.29
16	343	620			1.98	SQ	12.29
17	345	4			1.57	SQ	12.29
18	346	11			2.38	SQ	12.29
19							
20	Other Production -						
21	Lake Preston Peaking						
22	341	44			1.82	SQ	12.29
23	342	68			1.83	SQ	12.29
24	343	822			2.12	SQ	12.29
25	345	64			1.86	SQ	12.29
26	346	7			2.14	SQ	12.29
27							
28	Other Production -						
29	Jamestown Peaking #2						
30	341	8			4.29	SQ	12.30
31	342	14			3.19	SQ	12.29
32	343	1,145			2.45	SQ	12.29
33	345	16			3.30	SQ	12.30
34	346	9			2.56	SQ	12.29
35							
36	Other Production -						
37	Fergus Falls Control Cr						
38	343	393			2.92	SQ	22.79
39	Other Production -						
40	Solway Combustion Turb						
41	341	3,560			2.82	SQ	30.25
42	342	866			2.85	SQ	30.25
43	343	17,818			2.82	SQ	30.25
44	345	1,067			2.82	SQ	30.25
45	346	273			2.94	SQ	30.25
46							
47	OTHER PRODUCTION						
48	Langdon Wind Energy						
49	341				4.00	SQ	25.00
50	342				4.00	SQ	25.00

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

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	343				4.00	SQ	25.00
13	345	65,000			4.00	SQ	25.00
14	346				4.00		25.00
15	SUBTOTAL	91,926					
16							
17							
18	Transmission Plant						
19	353	34,084	45.00	-5.00	2.14	R1.5	31.09
20	354	2,123	55.00	-10.00	1.91	R5	28.91
21	355	36,632	55.00	-25.00	2.13	S1.5	37.30
22	356	40,213	55.00	-10.00	1.86	S1.5	39.10
23	358	16	40.00	-5.00	2.47	S4	11.53
24	SUBTOTAL	113,068					
25							
26	Distribution Plant -						
27	362	31,211	35.00	5.00	2.62	S-.5	24.50
28	364	29,757	60.00	-50.00	2.47	R3	42.58
29	365	23,564	58.00	-40.00	2.39	R2.5	40.28
30	366	6	50.00		1.88	R4	27.91
31	367	30,696	35.00	-5.00	2.91	R3	22.19
32	368	30,304	40.00	-5.00	2.47	R4	24.96
33	369	1,730	48.00	-100.00	4.03	S6	28.88
34	369.1	15,716	40.00	-30.00	3.12	R4	27.79
35	370	11,980	33.00		2.53	L1	23.92
36	370.1	6,847	20.00		4.71	R4	16.64
37	370.2	297	9.00		11.11	Amortized	
38	371		25.00		0.70	R3	2.59
39	371.2	2,466	19.00	10.00	4.50	L1	12.64
40	373	1,942	16.00	-5.00	5.88	L2	8.74
41	SUBTOTAL	186,516					
42							
43	General Plant -						
44	390	13,435	45.00	10.00	2.17	L1	32.30
45	390.1	3,337		-0.20	4.52	SQ	13.26
46	390.2	464		-0.20	4.45	SQ	13.26
47	390.3	2,482		-0.30	2.82	SQ	22.76
48	391	968	15.00		6.67	Amortized	
49	391.1	558	10.00		10.00	Amortized	
50	391.2	587	10.00		10.00	Amortized	

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	391.5	1,119	5.00		20.00	Amortized	
13	391.6	894	5.00		20.00	Amortized	
14	392	10,244					
15	Aircraft		7.00	39.00			
16	Autos		5.00	15.00			
17	Light Trucks		10.00	10.00			
18	Heavy Trucks & Semi		10.00	15.00			
19	Tractors (Includes		10.00	15.00			
20	Cranes)						
21	Trailers		15.00	10.00			
22	Portable Oil Purifier		10.00	20.00			
23	Trenchers		10.00	10.00			
24	Misc. Light Equip.		10.00	10.00			
25	Misc. Heavy Equip.		15.00	15.00			
26	393	2	15.00		6.67	Amortized	
27	394	1,448	15.00		6.67	Amortized	
28	394.2	694	15.00		6.67	Amortized	
29	395	47	15.00		6.67	Amortized	
30	396	300	15.00	20.00	7.35	S2	5.52
31	397	175	15.00		6.67	Amortized	
32	397.1	435	10.00		10.00	Amortized	
33	397.2	1,570	15.00		6.67	Amortized	
34	397.3	81	10.00		10.00	Amortized	
35	397.4	732	25.00	5.00	5.18	S5	10.23
36	SUBTOTAL	39,572					
37	TOTAL	559,405					
38							
39	SUBACCOUNTS USED						
40							
41							
42							
43							
44							
45							
46							
47							
48							
49							
50							

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 12/31/2008	2008/Q4

FOOTNOTE DATA

Schedule Page: 336.4 Line No.: 39 Column: a

SUBACCOUNTS USED
369.1 Underground Services
370.1 Load Management Switches
371.1 Rental Equipment
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
394.1 Central Stores Tools
394.2 AMR Equipment
397.1 Radio Telecommunication Equipment
397.2 Microwave Equipment
397.3 Radio Load Control Equipment
397.4 Communication Towers

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

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

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

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

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					
2	Regulatory Agency Assessments:				
3	MN Dept. of Commerce/Public Util. Commission	364,949		364,949	
4	SD Public Utilities Commission	38,640		38,640	
5	Federal Energy Regulatory Commission	198,834		198,834	
6					
7	Other Expenses:				
8	MN Public Utilities Commission:				
9	MN Rate Case (E017/GR-07-1178)	489,238	1,474,502	1,963,740	
10	Miscellaneous	107,178	123,095	230,273	
11					
12	ND Public Service Commission:				
13	ND Rate Case		228,889	228,889	
14	Miscellaneous	981	7,286	8,267	
15					
16	SD Public Utilities Commission:				
17	SD Rate Case		99,978	99,978	
18	Miscellaneous		918	918	
19					
20	FERC				
21	ER04-691-065 (MISO RSG)		100,035	100,035	
22	EL07-86 (Midwest ISO RSG Proceedings)		72,947	72,947	
23	ER08-370 (MRES Attachment O)		70,615	70,615	
24	Miscellaneous	50	115,627	115,677	
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	1,199,870	2,293,892	3,493,762	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
							2
Electric	928	364,949					3
Electric	928	38,640					4
Electric	928	198,834					5
							6
							7
							8
Electric	928	1,963,740	1,456,884			1,456,884	9
Electric	928	230,273					10
							11
							12
Electric	928	228,889					13
Electric	928	8,267					14
							15
							16
Electric	928	99,978					17
Electric	928	918					18
							19
							20
Electric	928	100,035					21
Electric	928	72,947					22
Electric	928	70,615					23
Electric	928	115,677					24
							25
							26
							27
							28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		3,493,762	1,456,884			1,456,884	46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

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

Classifications:

A. Electric R, D & D Performed Internally:
(1) Generation
a. hydroelectric
i. Recreation fish and wildlife
ii Other hydroelectric
b. Fossil-fuel steam
c. Internal combustion or gas turbine
d. Nuclear
e. Unconventional generation
f. Siting and heat rejection
(2) Transmission
a. Overhead
b. Underground
(3) Distribution
(4) Regional Transmission and Market Operation
(5) Environment (other than equipment)
(6) Other (Classify and include items in excess of $5,000.)
(7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
(1) Research Support to the electrical Research Council or the Electric Power Research Institute

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

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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $5,000 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 $5,000 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 Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
					3
					4
2,215		930.2	2,215		5
					6
					7
					8
2,215			2,215		9
					10
					11
	43,760	930.2	43,760		12
	8,246	930.2	8,246		13
					14
	230	930.2	230		15
					16
	52,236		52,236		17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
2,215	52,236		54,451		37
					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

DISTRIBUTION OF SALARIES AND WAGES

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	9,032,570		
4	Transmission	3,565,921		
5	Regional Market	1,460,273		
6	Distribution	4,981,049		
7	Customer Accounts	7,133,330		
8	Customer Service and Informational	1,749,364		
9	Sales	753,706		
10	Administrative and General	18,013,356		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	46,689,569		
12	Maintenance			
13	Production	4,545,954		
14	Transmission	2,013,808		
15	Regional Market	18,085		
16	Distribution	5,132,852		
17	Administrative and General	1,825,245		
18	TOTAL Maintenance (Total of lines 13 thru 17)	13,535,944		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	13,578,524		
21	Transmission (Enter Total of lines 4 and 14)	5,579,729		
22	Regional Market (Enter Total of Lines 5 and 15)	1,478,358		
23	Distribution (Enter Total of lines 6 and 16)	10,113,901		
24	Customer Accounts (Transcribe from line 7)	7,133,330		
25	Customer Service and Informational (Transcribe from line 8)	1,749,364		
26	Sales (Transcribe from line 9)	753,706		
27	Administrative and General (Enter Total of lines 10 and 17)	19,838,601		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	60,225,513		60,225,513
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

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 Terminaling 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)	60,225,513		60,225,513
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	11,856,873		11,856,873
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	11,856,873		11,856,873
72	Plant Removal (By Utility Departments)			
73	Electric Plant	16,638		16,638
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	16,638		16,638
77	Other Accounts (Specify, provide details in footnote):			
78	Fuel Stock (151)	74,357		74,357
79	Miscellaneous Deferred Debits (186)	568,157		568,157
80	Other Electric Revenue (456)	1,555,221		1,555,221
81	Expenses of Nonutility Operations (417.1)	818,638		818,638
82	Miscellaneous Nonoperating Income (421)	10,966,830		10,966,830
83	Exp. for Certain Civic, Politcal, and Related Activity (426.4	41,801		41,801
84	Other Deductions (426.5)	30,308		30,308
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	14,055,312		14,055,312
96	TOTAL SALARIES AND WAGES	86,154,336		86,154,336

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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.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

COMMON UTILITY PLANT AND EXPENSES

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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 currently available.				
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4

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.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	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	110,625	$/MW-Hr	18,198	8,049,817	$/MW-Hr	763,429
2	Reactive Supply and Voltage	294,601	$/MW-Hr	44,190	4,474,765	$/MW-Hr	669,263
3	Regulation and Frequency Response	21,573	$/MW-Hr	15,317	4,642,479	$/MW-Hr	486,532
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other				164,103	$/MW-Hr	17,198
8	Total (Lines 1 thru 7)	426,799		77,705	17,331,164		1,936,422

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

Line 1, Scheduling, System Control and Dispatch does not include $24,846 of services purchased from WAPA which was purchased with a "Unit of Measure" of $/Schedule - Day.

Schedule Page: 398 Line No.: 7 Column: e

Other is Generator Regulation and Frequency Response

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	688	22	1200	687	1				
2	February	675	19	1200	674	1				
3	March	677	3	800	676	1				
4	Total for Quarter 1	2,040			2,037	3				
5	April	593	1	800	592	1				
6	May	530	2	1000	529	1				
7	June	526	26	1800	525	1				
8	Total for Quarter 2	1,649			1,646	3				
9	July	582	31	1700	581	1				
10	August	602	18	1700	601	1				
11	September	517	1	1800	516	1				
12	Total for Quarter 3	1,701			1,698	3				
13	October	587	27	900	586	1				
14	November	650	21	800	649	1				
15	December	745	18	1500	743	2				
16	Total for Quarter 4	1,982			1,978	4				
17	Total Year to Date/Year	7,372			7,359	13				

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) _ A Resubmission	12/31/2008	2008/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.: 15 Column: b

The peak numbers for December are estimated and were developed using MISO CPNODE historical percentages of the total control area load at the time of the monthly peak.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	4,241,907
3	Steam	3,637,640			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	3,838
5	Hydro-Conventional	23,260			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	4,725,248
7	Other	199,341			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	27
9	Net Generation (Enter Total of lines 3 through 8)	3,860,241	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	12,802
10	Purchases	5,297,596	27	Total Energy Losses	74,623
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	9,058,445
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	135,728			
17	Delivered	235,120			
18	Net Transmission for Other (Line 16 minus line 17)	-99,392			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	9,058,445			

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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 on line 2 by month the system's output in Megawatt hours for each month.
(3) Report on line 3 by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
(4) Report on line 4 by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
(5) Report on lines 5 and 6 the specified information for each monthly peak load reported on line 4.

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	998,528	492,549	688	22	1200
30	February	991,466	531,405	675	19	1200
31	March	852,149	494,384	677	3	800
32	April	640,285	354,867	593	1	800
33	May	571,463	335,357	530	2	1000
34	June	672,878	335,541	526	26	1800
35	July	753,236	456,700	582	31	1700
36	August	843,882	503,617	602	18	1700
37	September	759,580	458,407	517	1	1800
38	October	662,402	335,196	587	27	900
39	November	687,285	301,519	650	21	800
40	December	625,291	125,706	745	18	1500
41	TOTAL	9,058,445	4,725,248			

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) __ A Resubmission	12/31/2008	2008/Q4

FOOTNOTE DATA

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

Includes interchange transactions and losses thereon.

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

Includes interchange transactions and losses thereon.

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

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

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Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Coyote* (b)	Plant Name: *Big Stone* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional
3	Year Originally Constructed	1981	1975
4	Year Last Unit was Installed	1981	1975
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	144.90	223.15
6	Net Peak Demand on Plant - MW (60 minutes)	149	256
7	Plant Hours Connected to Load	7978	8380
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	144	224
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	80	74
12	Net Generation, Exclusive of Plant Use - KWh	1016828472	1847067915
13	Cost of Plant: Land and Land Rights	718662	374603
14	Structures and Improvements	31545992	22586945
15	Equipment Costs	115742462	111056321
16	Asset Retirement Costs	101890	16972
17	Total Cost	148109006	134034841
18	Cost per KW of Installed Capacity (line 17/5) Including	1022.1463	600.6491
19	Production Expenses: Oper, Supv, & Engr	496509	501844
20	Fuel	14716817	35806255
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	1804720	577514
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	556361	910344
26	Misc Steam (or Nuclear) Power Expenses	708283	2099068
27	Rents	438	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	215364	275171
30	Maintenance of Structures	177686	242675
31	Maintenance of Boiler (or reactor) Plant	1996102	1927936
32	Maintenance of Electric Plant	232660	632204
33	Maintenance of Misc Steam (or Nuclear) Plant	265818	275955
34	Total Production Expenses	21170758	43248966
35	Expenses per Net KWh	0.0208	0.0234

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil		Coal-Subbit	Oil	TDF
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		Tons	Barrels	Tons
38	Quantity (Units) of Fuel Burned	849917	4776	0	1137881	2243	5857
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	6859	140000	0	8398	140000	15000
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	16.430	126.380	0.000	30.070	126.040	23.850
41	Average Cost of Fuel per Unit Burned	16.320	95.930	0.000	29.800	121.420	23.850
42	Average Cost of Fuel Burned per Million BTU	1.190	16.314	0.000	1.774	20.650	0.795
43	Average Cost of Fuel Burned per KWh Net Gen	0.014	0.000	0.000	0.019	0.000	0.000
44	Average BTU per KWh Net Generation	11457.000	0.000	0.000	10497.000	0.000	0.000

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Lake Preston* (b)			Plant Name: *Solway* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1978			2003		
4	Year Last Unit was Installed	1978			2003		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	24.10			44.00		
6	Net Peak Demand on Plant - MW (60 minutes)	26			47		
7	Plant Hours Connected to Load	44			1836		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	20			49		
10	When Limited by Condenser Water	20			49		
11	Average Number of Employees	1			2		
12	Net Generation, Exclusive of Plant Use - KWh	316260			47234160		
13	Cost of Plant: Land and Land Rights	12339			89809		
14	Structures and Improvements	194155			4205071		
15	Equipment Costs	3766473			23288827		
16	Asset Retirement Costs	0			0		
17	Total Cost	3972967			27583707		
18	Cost per KW of Installed Capacity (line 17/5) Including	164.8534			626.9024		
19	Production Expenses: Oper, Supv, & Engr	0			725		
20	Fuel	141398			4583257		
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	16785			545938		
26	Misc Steam (or Nuclear) Power Expenses	3540			69089		
27	Rents	0			3112		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			2631		
30	Maintenance of Structures	495			12027		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	29360			707048		
33	Maintenance of Misc Steam (or Nuclear) Plant	6387			13877		
34	Total Production Expenses	197965			5937704		
35	Expenses per Net KWh	0.6260			0.1257		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Oil			Natural Gas	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Barrels			MMBTU	Barrels	
38	Quantity (Units) of Fuel Burned	1463	0	0	546755	614	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	140000	0	0	545600	140000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	87.230	0.000	0.000	8.290	0.000	0.000
41	Average Cost of Fuel per Unit Burned	96.640	0.000	0.000	8.290	80.890	0.000
42	Average Cost of Fuel Burned per Million BTU	16.436	0.000	0.000	8.290	13.757	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.447	0.000	0.000	0.097	0.000	0.000
44	Average BTU per KWh Net Generation	27201.000	0.000	0.000	11652.000	0.000	0.000

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

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

Plant Name: *Big Stone (Cont.)* (d)			Plant Name: *Hoot Lake* (e)			Plant Name: *Jamestown* (f)			Line No.
			Steam			Gas Turbine			1
			Conventional			Conventional			2
			1959			1976			3
			1964			1978			4
0.00			119.50			48.20			5
0			144			54			6
0			13497			132			7
0			0			0			8
0			144			42			9
0			0			42			10
0			49			1			11
0			765991800			1286228			12
0			346382			24614			13
0			5701405			244250			14
0			46185334			7068295			15
0			130498			0			16
0			52363619			7337159			17
0.0000			438.1893			152.2232			18
0			391535			0			19
0			18477743			466984			20
0			0			0			21
0			784177			0			22
0			0			0			23
0			0			0			24
0			920261			39253			25
0			1139030			3714			26
0			9374			746			27
0			0			0			28
0			227009			509			29
0			226265			1183			30
0			2356595			0			31
0			2070914			195995			32
0			559755			6393			33
0			27162658			714777			34
0.0000			0.0355			0.5557			35
RRM			Coal	Oil		Oil			36
Tons			Tons	Barrels		Barrels			37
543	0	0	470356	1737	0	2432	0	0	38
7187	0	0	9311	140000	0	140000	0	0	39
8.500	0.000	0.000	38.200	122.470	0.000	121.000	0.000	0.000	40
8.500	0.000	0.000	37.660	126.040	0.000	101.470	0.000	0.000	41
0.591	0.000	0.000	2.023	21.436	0.000	17.257	0.000	0.000	42
0.000	0.000	0.000	0.024	0.000	0.000	0.363	0.000	0.000	43
0.000	0.000	0.000	11440.000	0.000	0.000	11116.000	0.000	0.000	44

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

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

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
		0.00			0.00			0.00	5
		0			0			0	6
		0			0			0	7
		0			0			0	8
		0			0			0	9
		0			0			0	10
		0			0			0	11
		0			0			0	12
		0			0			0	13
		0			0			0	14
		0			0			0	15
		0			0			0	16
		0			0			0	17
		0.0000			0.0000			0.0000	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	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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: (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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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

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

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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. 0 Plant Name: (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
			1
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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	3,740,480	562,931
3	Wright	1922	0.40	0.5	3,021,932	846,582
4	Pisgah	1917	0.52	0.7	4,534,139	416,504
5	Dayton Hollow	1909	0.97	1.0	6,751,537	619,803
6	Taplin Gorge	1925	0.56	0.5	4,068,262	639,176
7	Bemidji	-	0.74	0.2	1,143,713	679,656
8						
9	Internal Combustion:					
10	Fergus Control Center	1995	1.83	2.1	18,207	591,638
11	Diesel Generators		2.26	1.7		
12						
13						
14						
15						
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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 Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
715,287	2,652		44,594	-		2
1,679,726	2,994		47,203	-		3
569,773	8,172		55,408	-		4
608,844	3,606		58,684	-		5
1,224,475	2,914		30,039	-		6
3,775,867	47,727		67,063	-		7
						8
						9
289,310	4,048		7,801	Oil		10
				Oil		11
						12
						13
						14
						15
						16
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) __ A Resubmission	12/31/2008	2008/Q4

FOOTNOTE DATA

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

Various.

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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	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Center	Maple River	345.00	345.00	Alum Tower	48.00		1
2								
3								
4	Fergus Falls	Henning	230.00	230.00	Wood H	20.00		1
5	Fergus Falls	Wahpeton	230.00	230.00	Wood H	29.00		1
6	Wahpeton	Hankinson	230.00	230.00	Wood H	25.00		1
7	Hankinson	Forman	230.00	230.00	Wood H	36.00		1
8	Forman	Ellendale	230.00	230.00	Wood H	48.00		1
9	Audubon (W 1/10)	Badoura	230.00	230.00	Wood H	6.00		1
10	Audubon	Maple River	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)	Winnepeg	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)	Gary	230.00	230.00	Wood H	15.00		1
15	Harvey	Underwood	230.00	230.00	Wood H	72.00		1
16	Underwood	Coal Creek	230.00	230.00	Wood H	3.00		1
17	Harvey	Rugby	230.00	230.00	Steel H	40.00		1
18								
19								
20								
21								
22		Total	115.00	115.00	Wood H	449.00		
23		Total	115.00	115.00	SWP	373.00		
24		Total	69.00	69.00		212.00		
25								
26								
27								
28								
29								
30		Total	41.60	41.60	SWP	3,800.00		
31		Total	41.60	41.60	Underground	1.00		
32								
33								
34								
35								
36					TOTAL	5,287.00		15

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/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	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
		5,458,744	5,458,744					1
								2
								3
	6,339	549,602	555,941					4
	5,935	675,257	681,192					5
		475,142	475,142					6
		766,769	766,769					7
		1,133,627	1,133,627					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
		10,184,441	10,184,441					15
		402,272	402,272					16
		7,619,960	7,619,960					17
								18
								19
								20
								21
	74,783	5,941,485	6,016,268					22
	49,282	22,421,249	22,470,531					23
		5,941,358	5,941,358					24
								25
								26
								27
								28
								29
	4,953	72,770,862	72,775,815					30
		53,066	53,066					31
								32
								33
								34
				4,821,547	2,080,005	71,274	6,972,826	35
	141,292	139,479,971	139,621,263	4,821,547	2,080,005	71,274	6,972,826	36

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Schedule Page: 422 Line No.: 35 Column: m

Columns m, n, o, and p detail by line not available.

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TRANSMISSION LINES ADDED DURING YEAR

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

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Switch number 249	Rush Lake Sub	2.60	Single Pole	22.00	1	1
2	Crookston Parkview Sub	Crookston Amererica Crys	2.50	Single Pole	18.00	1	1
3	Hensel 115 kV Sub	west towards Langdon	10.86	Single Pole	18.00	1	1
4	Mapleton	Casselton	11.89	Single Pole	20.00	2	2
5							
6							
7							
8							
9							
10							
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41							
42							
43							
44	TOTAL		27.85		78.00	5	5

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TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
10RT2	ACSR	3102 vert	41		189,551	152,933	342,484	684,968	1
10RT2	ACSR	3102 vert	41		274,936	230,660	505,596	1,011,192	2
477RT2	ACSR	3651 vert	115		862,779	1,251,876	2,114,655	4,229,310	3
795	ACSS	3651 vert	115		1,441,014	2,090,883	3,531,897	7,063,794	4
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									41
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									43
					2,768,280	3,726,352	6,494,632	12,989,264	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	Bemidji, MN	Transmission	115.00	69.00	13.80
2			41.60	2.40	
3			15.70	2.40	
4	Big Stone, SD Highway 12	Transmission	115.00	41.60	
5	Big Stone, SD Plant	Transmission	22.90	230.00	13.80
6			230.00	115.00	
7			23.60	13.80	
8			115.00	12.50	
9	Browns Valley, MN	Transmission	230.00	41.60	
10			41.60	4.16	
11	Buffalo, ND	Transmission	345.00	115.00	43.00
12			41.60	2.40	
13			41.60	2.40	
14	Canby, MN	Transmission	115.00	41.60	
15			41.60	4.16	
16	Cass Lake, MN	Transmission	115.00	41.60	
17	Clearbrook, MN	Transmisison	115.00	41.60	
18			41.60	13.80	
19	Crookston, MN	Transmission	115.00	41.60	
20			115.00	41.60	
21			41.90	2.30	
22	Center, ND	Transmission	345.00	230.00	13.80
23	Devils Lake, ND	Transmission	115.00	41.60	
24			41.60	2.40	
25	Devils Lake, ND	Transmission	115.00	41.60	
26	Donaldson, MN	Transmission	115.00	41.60	
27			115.00	41.60	
28			41.60	2.40	
29	Fergus Falls, MN Edgetown	Transmission	115.00	12.50	
30	Fertile, MN	Transmission	115.00	41.60	
31			41.60	2.30	
32	Finley, ND	Transmission	115.00	41.60	
33			41.60	2.40	
34			41.60	2.40	
35	Forman, ND	Transmission	230.00	115.00	41.60
36			41.60	4.16	
37			41.60	12.50	
38	Hetland, SD 115kv	Transmission	115.00	41.60	
39	Hoot Lake Plant, Fergus Falls, MN	Transmission	14.40	41.60	
40	Hoot Lake 115 kv, Fergus Falls, MN	Transmission	14.40	115.00	

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SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1			14.40	115.00	
2			115.00	43.80	
3			115.00	12.50	
4	Jamestown, ND 345 kv	Transmission	345.00	115.00	43.00
5			41.60	2.40	
6			41.60	2.40	
7	Jamestown, ND Peaking Plant	Transmission	115.00	41.60	
8			41.60	12.50	
9			41.60	7.20	
10	Lake Preston, SD Peaking Plant	Transmission	41.60	12.50	
11			41.60	4.16	
12			12.50	4.16	
13	Maple River	Transmission	345.00	230.00	13.80
14	Mapleton, ND 115 kv	Transmission	115.00	41.60	
15	Marietta, MN 115 kv	Transmission	115.00	41.60	
16			41.60	2.40	
17	Northwood, ND 115kv	Transmission	115.00	41.60	
18	Oakes, ND 230 kv	Transmission	230.00	41.60	
19			41.60	4.16	
20	Ortonville, MN 115 kv	Transmission	115.00	41.60	
21	Pelican Rapids, MN	Transmission	115.00	41.60	
22	Plummer, MN 115 kv	Transmission	115.00	41.60	
23	Rugby, ND 230 kv	Transmission	230.00	115.00	13.80
24	Solway, MN 115 kv	Transmission	115.00	13.80	
25	Toronto, SD	Transmission	115.00	41.60	
26			41.60	2.40	
27	Wahpeton, ND North	Transmission	115.00	41.60	
28	Wilton, MN	Transmission	230.00	115.00	13.80
29			41.60	2.40	
30	Winger, MN	Transmission	230.00	115.00	
31			41.60	7.20	
32			41.60	2.40	
33					
34	Transmission Subtotal:		7409.80	3071.76	210.40
35	Transmission Subs Under 10,000 kva				
36	Transmission Total		7409.80	3071.76	210.40
37					
38					
39	Bemidji, MN Airport	Distribution	41.60	12.50	
40	Bemidji, MN 25th Street	Distribution	69.00	12.50	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

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	Bemidji, MN Nymore	Distribution	69.00	12.50	
2	Bemidji, MN Potlatch	Distribution	69.00	12.50	
3	Casselton, ND	Distribution	41.60	12.50	
4	Clearbrook, MN Pipeline	Distribution	115.00	12.50	
5	Cooperstown, ND	Distribution	41.60	12.50	
6	Crookston, MN Uptown	Distribution	41.60	12.50	
7	Crookston, MN Parkview	Distribution	41.60	12.50	
8	Crookston, MN Simplot Jiffy Fry	Distribution	41.60	12.50	
9	Dawson, MN Dawson Mills	Distribution	41.60	12.50	
10	Devils Lake, ND Downtown	Distribution	41.60	4.16	
11	Enderlin, ND	Distribution	115.00	12.50	
12	Fairmount, ND	Distribution	69.00	12.50	
13	Gwinner, ND	Distribution	115.00	12.50	
14	Harvey, ND Northwest	Distribution	115.00	12.50	
15	Itasca, MN Minnesota Pipeline	Distribution	115.00	4.16	
16	Jamestown, ND Southwest	Distribution	41.60	12.50	
17	Jamestown, ND Downtown	Distribution	41.60	12.50	
18	Jamestown, ND Potato	Distribution	41.60	12.50	
19	Jamestown, ND North	Distribution	41.60	12.50	
20	Lake Norden, SD Dairy	Distribution	41.60	12.50	
21	Lisbon, ND Town	Distribution	115.00	12.50	
22	Mahnomen, MN	Distribution	115.00	12.50	
23	Milbank, SD South	Distribution	41.60	12.50	
24	Milbank, SD Northwest	Distribution	41.60	12.50	
25	Morris, MN South	Distribution	41.60	12.50	
26	Morris, MN Northeast	Distribution	41.60	12.50	
27	Perham, MN	Distribution	41.60	12.50	
28	Pelican Rapids, MN Turkey Plant	Distribution	41.60	12.50	
29	Rosholt, SD	Distribution	41.60	12.50	
30	Rugby, ND South	Distribution	41.60	12.50	
31	Spiritwood, ND Ladish	Distribution	41.60	12.50	
32	Spiritwood, ND Ladish	Distribution	115.00	41.60	
33	Wahpeton, ND Northwest	Distribution	41.60	12.50	
34	Wheaton, MN South	Distribution	115.00	12.50	
35	Distribution Subtotal:		2267.80	462.42	
36	Distribution Under 10,000 kva				
37	Distribution Total		2267.80	462.42	
38	Transmission From Above				
39	Transmission & Distribution				
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (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 Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
18	1					1
	3					2
2	3					3
45	1					4
460	1					5
233	1					6
39	1					7
16	1					8
26	1					9
5	1					10
112	1					11
2	3					12
	1					13
27	1					14
5	1					15
19	1					16
11	1					17
	3					18
39	1					19
56	1					20
	1					21
336	1					22
34	1					23
	3					24
57	1					25
10	1					26
10	1					27
3	1					28
37	1					29
10	1					30
1	3					31
60	1					32
2	3					33
	1					34
140	1					35
2	1					36
	1					37
45	1					38
10	1					39
84	1					40

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SUBSTATIONS (Continued)

5. Show in columns (I), (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 Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
60	1					1
27	1					2
37	1					3
224	2					4
1	3					5
3	1					6
56	1					7
56	2					8
5	1					9
28	1					10
3	1					11
1	3					12
672	2					13
20	1					14
10	1					15
	3					16
13	1					17
34	1					18
	3					19
22	2					20
12	1					21
34	2					22
125	1					23
80	1					24
45	1					25
	1					26
24	2					27
140	1					28
1	3					29
140	1					30
1	3					31
	1					32
						33
3830	104					34
34	16					35
3864	120					36
						37
						38
14	1					39
15	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2008	End of 2008/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (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 Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
14	1					1
11	1					2
10	1					3
22	2					4
10	1					5
15	1					6
10	1					7
10	1					8
24	3					9
10	1					10
19	2					11
10	3					12
20	2					13
14	1					14
11	1					15
14	1					16
14	1					17
14	1					18
14	1					19
12	1					20
14	1					21
14	1					22
10	1					23
25	1					24
12	3					25
12	1					26
28	2					27
10	1					28
10	1					29
10	1					30
50	2					31
35	4					32
20	2					33
12	1					34
569	51					35
873	483					36
1442	534					37
3864						38
5306						39
						40

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) _ A Resubmission	12/31/2008	2008/Q4

FOOTNOTE DATA

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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.

Column C, D and E data is reported in KVA.

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