

THIS FILING IS

Item 1: ☒ An Initial (Original)
Submission

OR ☐ Resubmission No. _____

Form 1 Approved
OMB No. 1902-0021
(Expires 7/31/2008)
Form 1-F Approved
OMB No. 1902-0029
(Expires 6/30/2007)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 6/30/2007)

PAC-E



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08 APR 30 AM 9:59
FEDERAL ENERGY
UTILITIES COMMISSION

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)

PacifiCorp

Year/Period of Report

End of 2007/Q4



**ROCKY MOUNTAIN
POWER**
A DIVISION OF PACIFICORP

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08 APR 30 AM 9:59

IDAHO PUBLIC
UTILITIES COMMISSION

201 South Main, Suite 2300
Salt Lake City, Utah 84111

April 29, 2008

VIA OVERNIGHT DELIVERY

Idaho Public Utilities Commission
472 West Washington
Boise, ID 83702-5983

Attention: Jean D. Jewell
Commission Secretary

RE: FERC Form 1

PacifiCorp (d.b.a. Rocky Mountain Power) submits for filing one copy of PacifiCorp's annual FERC Form 1 report for the year ended December 31, 2007.

PacifiCorp respectfully requests that all data requests regarding this matter be addressed to:

By email (**preferred**): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232

By fax: (503) 813-6060

Please direct any informal questions to Ted Weston, Regulatory Manager, at (801) 220-2963.

Sincerely,

Jeffrey K. Larsen
Vice President, Regulation

Enclosure

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 filed..."

General Penalties

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

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

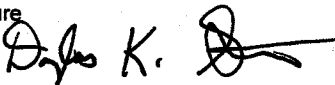
IDENTIFICATION

01 Exact Legal Name of Respondent PacifiCorp		02 Year/Period of Report End of <u>2007/Q4</u>
03 Previous Name and Date of Change (if name changed during year) <div style="text-align: center;">/ /</div>		
04 Address of Principal Office at End of Period (Street, City, State, Zip Code) 825 N.E. Multnomah, Suite 1900, Portland, OR 97232		
05 Name of Contact Person Henry E. Lay		06 Title of Contact Person Corporate Controller
07 Address of Contact Person (Street, City, State, Zip Code) 825 N.E. Multnomah, Suite 1900, Portland, OR 97232		
08 Telephone of Contact Person, Including Area Code (503) 813-6179	09 This Report Is (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	10 Date of Report (Mo, Da, Yr) 04/04/2008

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 Douglas K. Stuver	03 Signature  Douglas K. Stuver	04 Date Signed (Mo, Da, Yr) 04/04/2008
02 Title Senior VP & Chief Financial Officer		

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

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Important Changes During the Year	108-109	
7	Comparative Balance Sheet	110-113	
8	Statement of Income for the Year	114-117	
9	Statement of Retained Earnings for the Year	118-119	
10	Statement of Cash Flows	120-121	
11	Notes to Financial Statements	122-123	
12	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
13	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
14	Nuclear Fuel Materials	202-203	N/A
15	Electric Plant in Service	204-207	
16	Electric Plant Leased to Others	213	N/A
17	Electric Plant Held for Future Use	214	
18	Construction Work in Progress-Electric	216	
19	Accumulated Provision for Depreciation of Electric Utility Plant	219	
20	Investment of Subsidiary Companies	224-225	
21	Materials and Supplies	227	
22	Allowances	228-229	
23	Extraordinary Property Losses	230	N/A
24	Unrecovered Plant and Regulatory Study Costs	230	
25	Transmission Service and Generation Interconnection Study Costs	231	
26	Other Regulatory Assets	232	
27	Miscellaneous Deferred Debits	233	
28	Accumulated Deferred Income Taxes	234	
29	Capital Stock	250-251	
30	Other Paid-in Capital	253	
31	Capital Stock Expense	254	
32	Long-Term Debt	256-257	
33	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
34	Taxes Accrued, Prepaid and Charged During the Year	262-263	
35	Accumulated Deferred Investment Tax Credits	266-267	
36	Other Deferred Credits	269	

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/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			
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	N/A		
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	N/A		
55	Amounts included in ISO/RTO Settlement Statements	397	N/A		
56	Purchase and Sale of Ancillary Services	398			
57	Monthly Transmission System Peak Load	400			
58	Monthly ISO/RTO Transmission System Peak Load	400a	N/A		
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			
63	Pumped Storage Generating Plant Statistics	408-409	N/A		
64	Generating Plant Statistics Pages	410-411			
65	Transmission Line Statistics Pages	422-423			
66	Transmission Lines Added During the Year	424-425			

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Substations	426-427	
68	Footnote Data	450	
	Stockholders' Reports Check appropriate box: <input checked="" type="checkbox"/> Four copies will be submitted <input type="checkbox"/> No annual report to stockholders is prepared		

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report <i>(Mo, Da, Yr)</i> 04/03/2008	Year/Period of Report End of <u>2007/Q4</u>
GENERAL INFORMATION			
<p>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.</p> <div style="display: flex; justify-content: space-between;"> <div style="width: 60%;"> <p>Douglas K. Stuver, Senior Vice President and Chief Financial Officer 825 N.E. Multnomah, Suite 1900 Portland, OR 97232-4116</p> </div> <div style="width: 35%;"> <p>Corporate Books are kept at: 825 N.E. Multnomah, Suite 1900 Portland, OR 97232-4116</p> </div> </div>			
<p>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.</p> <p>Incorporated on August 11, 1987 in the State of Oregon</p>			
<p>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.</p> <p>Not applicable</p>			
<p>4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.</p> <p>The Company is a regulated electric company operating in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. The Company conducts its retail electric utility business as Pacific Power and Rocky Mountain Power, and engages in electricity production and sales on a wholesale basis under the trade name PacifiCorp Energy.</p>			
<p>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?</p> <p>(1) <input type="checkbox"/> Yes...Enter the date when such independent accountant was initially engaged: (2) <input checked="" type="checkbox"/> No</p>			

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
CONTROL OVER RESPONDENT			
<p>1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.</p>			
Berkshire Hathaway Inc.			
MidAmerican Energy Holdings Company (100%) (88.2% controlled by Berkshire Hathaway Inc.) PPW Holdings LLC (100% controlled by MidAmerican Energy Holdings Company) PacifiCorp (99.78% controlled by PPW Holdings LLC)			

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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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.
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	Centralia Mining Company	Mining	100	
2	Energy West Mining Company	Mining	100	
3	Glenrock Coal Company	Mining	100	
4	Interwest Mining Company	Mining	100	
5	Pacific Minerals, Inc.	Mining	100	
6	Bridger Coal Company	Mining	66.67	
7	PacifiCorp Environmental Remediation Company	Environmental Services	100	
8	PacifiCorp Future Generations, Inc.	Rain Forest Carbon Credits	100	
9	PacifiCorp Investment Management, Inc.	Management Services for PERCo	100	
10	Trapper Mining, Inc.	Mining	21.40	
11	Intermountain Geothermal Company	Steam Delivery Service		
12	Steam Reserve Corporation	Steam Delivery Service		
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Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 103 Line No.: 1 Column: a

In May 2000, the assets of Centralia Mining Company were sold to TransAlta.

Schedule Page: 103 Line No.: 6 Column: a

Idaho Power Corp. holds a 33.33% ownership interest in Bridger Coal Company. PacifiCorp's interest is held through Pacific Minerals, Inc.

Schedule Page: 103 Line No.: 7 Column: a

PacifiCorp Environmental Remediation Company ("PERCo") became a wholly owned subsidiary of PacifiCorp in April 2007, when PacifiCorp acquired the outstanding 10% minority interest in PERCo from CH2M HILL. For additional information refer to Page 108, *Important Changes During the Year*, Item 2, of this Form No. 1.

Schedule Page: 103 Line No.: 8 Column: a

PacifiCorp Future Generations owns an interest in Canopy Botanicals, Inc., which holds an interest in Canopy Botanicals, SRL relating to rain forest carbon emissions credits.

Schedule Page: 103 Line No.: 10 Column: a

The other joint owners of Trapper Mining, Inc. are Salt River Project (32.10%), Tri-State Generation and Transmission Association, Inc. (26.57%) and Platte River Power Authority (19.93%).

Schedule Page: 103 Line No.: 11 Column: a

Intermountain Geothermal Company was merged with and into its direct parent, PacifiCorp, on August 31, 2007, with PacifiCorp surviving. For additional information refer to Page 108, *Important Changes During the Year*, Item 2, of this Form No. 1.

Schedule Page: 103 Line No.: 12 Column: a

Steam Reserve Corporation was merged with and into its direct parent, Intermountain Geothermal Company, on August 30, 2007, with Intermountain Geothermal Company surviving. For additional information refer to Page 108, *Important Changes During the Year*, Item 2, of this Form No. 1.

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is \$50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Executive Officers as of December 31, 2007		
2	Chairman of the Board and Chief Executive Officer	Gregory E. Abel	
3	Senior Vice President and Chief Financial Officer	David J. Mendez	214,200
4	President, Rocky Mountain Power	A. Richard Walje	335,811
5	President, Pacific Power	R. Patrick Reiten	250,000
6	President, PacifiCorp Energy	A. Robert Lasich	173,580
7			
8	Other Executive Officers in 2007		
9	President, PacifiCorp Energy	William J. Fehman	521,431
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Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 104 Line No.: 1 Column: a

PacifiCorp sets forth the salary information for its "named executive officers" for the year ended December 31, 2007, consistent with Item 402 of Regulation S-K promulgated by the Securities and Exchange Commission. Salary information of other officers will be provided to the Federal Energy Regulatory Commission (the "FERC") upon request, but the company considers such information personal and confidential to such officers. See 18 CFR 388.107(d), (f).

Schedule Page: 104 Line No.: 2 Column: b

Mr. Abel receives no direct compensation from PacifiCorp. PacifiCorp reimburses MidAmerican Energy Holdings Company ("MEHC") for the cost of Mr. Abel's time spent on PacifiCorp matters, including compensation paid to him by MEHC, pursuant to an intercompany administrative services agreement among MEHC and its subsidiaries. Please refer to MEHC's annual report on Form 10-K for the year ended December 31, 2007 (File No. 001-14881) for executive compensation information for Mr. Abel.

Schedule Page: 104 Line No.: 3 Column: b

For additional information regarding changes in the status of PacifiCorp's officers refer to page 108, *Important Changes During the Year*, Item 13, of this Form No. 1. On February 8, 2008, Mr. Mendez resigned as a director and executive officer of PacifiCorp effective February 29, 2008.

Schedule Page: 104 Line No.: 6 Column: b

For additional information regarding changes in the status of PacifiCorp's officers refer to page 108, *Important Changes During the Year*, Item 13, of this Form No. 1.

Schedule Page: 104 Line No.: 8 Column: a

PacifiCorp sets forth the salary information for its "named executive officers" for the year ended December 31, 2007, consistent with Item 402 of Regulation S-K promulgated by the Securities and Exchange Commission. Salary information of other officers will be provided to the FERC upon request, but the company considers such information personal and confidential to such officers. See 18 CFR 388.107(d), (f).

Schedule Page: 104 Line No.: 9 Column: b

For additional information regarding changes in the status of PacifiCorp's officers refer to page 108, *Important Changes During the Year*, Item 13, of this Form No. 1. Mr. Fehrman resigned as a director and executive officer of PacifiCorp on August 30, 2007.

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/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	PacifiCorp Board of Directors as of December 31, 2007:			
2	Gregory E. Abel (Chairman of the Board and CEO, PacifiCorp)	666 Grand Avenue, Suite DM29, Des Moines, Iowa 50309		
3	Patrick Reiten (President, Pacific Power)	825 NE Multnomah, Suite 2000, Portland, Oregon 97232		
4	A. Richard Walje (President, Rocky Mountain Power)	201 South Main, Suite 2400, Salt Lake City, Utah 84140		
5	Douglas L. Anderson	302 South 36th Street, Omaha, Nebraska 68131		
6	Brent E. Gale	825 NE Multnomah, Suite 2000, Portland, Oregon 97232		
7	Patrick J. Goodman	666 Grand Avenue, Suite DM29, Des Moines, Iowa 50309		
8	A. R. Lasich (President, PacifiCorp Energy)	1407 West North Temple, Suite 320, Salt Lake City, Utah 84116		
9	Mark C. Moench	201 South Main, Suite 2400, Salt Lake City, Utah 84140		
10	Natalie L. Hocken	825 NE Multnomah, Suite 2000, Portland, Oregon 97232		
11	David J. Mendez (Senior VP and Chief Financial Officer)	825 NE Multnomah, Suite 1900, Portland, Oregon 97232		
12				
13				
14				
15	Other Directors in 2007			
16	William J. Fehman (President, PacifiCorp Energy)	1407 West North Temple, Suite 320, Salt Lake City, Utah 84116		
17	Nolan E. Karras	4695 South 1900 West #3, Roy, Utah 84067		
18	Stanley K. Walters (Senior Vice President, PacifiCorp)	825 NE Multnomah, Suite 2000, Portland, Oregon 97232		
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Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 105 Line No.: 2 Column: a

Currently there is only one committee, a Compensation Committee, of which the sole member is Mr. Abel.

Schedule Page: 105 Line No.: 10 Column: a

Ms. Hocken was elected August 30, 2007. For additional information regarding Ms. Hocken refer to Page 108, *Important Changes During the Year*, Item 13, of this Form No. 1.

Schedule Page: 105 Line No.: 11 Column: a

Mr. Mendez was elected August 30, 2007. For additional information regarding Mr. Mendez refer to Page 108, *Important Changes During the Year*, Item 13, of this Form No. 1.

Schedule Page: 105 Line No.: 16 Column: a

Mr. Fehrman resigned as a director on August 30, 2007. For additional information regarding Mr. Fehrman refer to Page 108, *Important Changes During the Year*, Item 13, of this Form No. 1.

Schedule Page: 105 Line No.: 17 Column: a

Mr. Karras resigned as a director effective July 25, 2007. For additional information regarding Mr. Karras refer to Page 108, *Important Changes During the Year*, Item 13, of this Form No. 1.

Schedule Page: 105 Line No.: 18 Column: a

Mr. Watters resigned as a director effective March 16, 2007. For additional information regarding Mr. Watters refer to Page 108, *Important Changes During the Year*, Item 13, of this Form No. 1.

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(Next Page is 108)

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report 04/03/2008	Year/Period of Report End of 2007/Q4
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 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.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
PacifiCorp			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

ITEM 1.

Changes in Franchise Rights

<u>State</u>	<u>Effective Date</u>	<u>Expiration Date</u>	<u>Fee</u> (Fee attached to franchise agreement)
<u>California (a)</u>			
None			
<u>Idaho (b)</u>			
Arco	08/10/2007	08/10/2017	3.0%
<u>Oregon (c)</u>			
Bend	08/31/2007	08/31/2017	5.0%
Corvallis	09/19/2007	09/19/2017	5.0%
Enterprise	09/10/2007	06/30/2017	7.0%
Halsey	12/11/2007	12/11/2027	3.5%
Harrisburg	07/01/2007	07/01/2027	(e)
Helix	03/23/2007	03/23/2027	7.0%
Lakeview	07/01/2007	06/30/2017	(f)
Maywood Park	07/05/2007	07/05/2017	5.0%
Medford	04/01/2007	08/05/2022	7.0%
Myrtle Creek	05/29/2007	05/29/2017	7.0%
Portland	04/07/2007	04/07/2027	5.0%
Redmond	07/26/2007	07/26/2012	7.0%
<u>Utah (b)</u>			
Brian Head	12/07/2007	12/07/2032	6.0%
Cirleville	07/16/2007	07/16/2032	-
Cottonwood Heights	08/07/2007	08/07/2017	-
Kaysville	10/02/2007	Indefinite	-
Midvale	10/08/2007	10/08/2057	6.0%
Provo	12/31/2007	06/30/2013	6.0%
Rockville	09/17/2007	09/17/2037	-
Sandy	06/19/2007	01/30/2016	6.0%
<u>Washington (b)</u>			
Benton County	04/02/2007	02/29/2012	-
Mabton	04/10/2007	04/10/2027	6.0%
Union Gap	07/17/2007	07/17/2027	6.0%
Wapato	04/20/2007	04/20/2027	6.0%
<u>Wyoming (d)</u>			
Kirby	09/17/2007	09/17/2032	2.0%
Lander	04/12/2007	04/12/2032	4.0%
Pinedale	06/21/2007	06/21/2032	2.0%

- (a) In California, franchise fees are an expense to PacifiCorp and are embedded in rates.
- (b) In Idaho, Utah and Washington, PacifiCorp collects franchise fees from customers and remits them directly to the applicable municipalities.
- (c) In Oregon, the first 3.5% of the franchise fee is an expense to PacifiCorp and is embedded in rates. Any amount above the 3.5% is collected from customers and remitted directly to the applicable municipalities.

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

- (d) In Wyoming, the first 1.0% of the franchise fees is an expense to PacifiCorp and is embedded in rates. Any amount above the 1.0% is collected from customers and remitted directly to the applicable municipalities.
- (e) 4.5% from 7/01/2007 through 6/30/2009; 5.5% from 7/01/2009 through 7/01/2027.
- (f) 5.0% from 7/01/2007 through 6/30/2012; 7.0% from 7/01/2012 through 6/30/2017.

ITEM 2.

Acquisition of Ownership in Other Companies

PacifiCorp Environmental Remediation Company

PacifiCorp Environmental Remediation Company ("PERCo") became a wholly owned subsidiary of PacifiCorp in April 2007, when PacifiCorp acquired the outstanding 10% minority interest in PERCo for \$150,000. No commission approval was required.

Intermountain Geothermal and Steam Reserve Corporation

Steam Reserve Corporation was merged with and into its direct parent, Intermountain Geothermal Company, on August 30, 2007, with Intermountain Geothermal Company surviving. Subsequently, Intermountain Geothermal Company was merged with and into its direct parent, PacifiCorp, on August 31, 2007, with PacifiCorp surviving. As a result, effective September 1, 2007, all assets and liabilities of Steam Reserve Corporation and Intermountain Geothermal Company reside at PacifiCorp. No commission approval was required.

ITEM 3.

Purchase or Sale of an Operating Unit

On September 14, 2007, PacifiCorp closed the sale of the Upper Beaver Hydroelectric Project, Federal Energy Regulatory Commission ("FERC") Project No. 814, assets and water rights, to the City of Beaver, Utah, for \$2 million. In accordance with 18 CFR Part 4.94 (f) Article 6, notification of the transfer of the license exemption was filed with the FERC. The Upper Beaver Hydroelectric Project is located in southwestern Utah, on the Beaver River near the City of Beaver, upon United States Forest Service ("USFS") lands in the Fish Lake National Forest, and operated under the authority of a special use permit with the USFS. The proceeds, net book value, and selling costs were transferred to account 102, Electric plant purchased or sold. In March 2008, PacifiCorp filed with the FERC the journal entries called for by the Uniform System of Accounts. The sale was approved by the Wyoming, Oregon and California state commissions.

ITEM 4.

Important Leaseholds

Goodnoe Hills Wind Project

In April 2007, PacifiCorp concluded the purchase of the 94.0-megawatt ("MW") Goodnoe Hills Wind Project from Northwest Wind Partners, LLC ("Northwest"), currently under construction near Goldendale, Washington. As a result of the acquisition, PacifiCorp was assigned and assumed five 25-year real estate leases from Northwest with private land owners. The leases have one 25-year extension available at PacifiCorp's option. The leases have annual initial term rent payments; one-time installation fees based on the installed megawatt capacity; and four of the leases have operating rent payments with minimum lease payment obligations based on installed megawatt of capacity. The remaining lease has operating rent payments based on a millage rate per kilowatt hour determined by a percentage of an adjusted Powerdex Mid-Columbia weighted-average hourly index and subject to a cap.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
PacifiCorp			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

Marengo II Wind Project

In September 2007, PacifiCorp announced the purchase of the 70.2-MW Marengo II wind project from Blue Sky Wind, LLC, currently under construction near Dayton, Washington. As a result of this acquisition, PacifiCorp was assigned and assumed one 35-year and one 30-year wind energy ground leases and transmission access easements from Blue Sky Wind, LLC, for use of the underlying land for the project. Both leases are with private land owners and have extensions available through 2055 and 2056 at PacifiCorp's option. Both leases call for the payment of one-time installation fees based on the installed megawatt capacity and monthly production payments based on a millage rate per kilowatt hour of energy generated. Monthly production payments are subject to annual inflationary increases. Both leases call for annual floor minimum payments based on the greater of: (1) the monthly production payments; (2) a fixed annual amount; or (3) a fixed amount per installed megawatt capacity.

ITEM 5.

Important Extension and Reduction of Transmission or Distribution System

For a discussion of transmission lines added during the year, refer to pages 424-425 of this Form No. 1. During the year ended December 31, 2007, PacifiCorp did not significantly increase or decrease its distribution system.

ITEM 6.

Financing Activities

Short-Term Debt

PacifiCorp had no short-term debt outstanding at December 31, 2007. Authorizations during the year ended December 31, 2007 for up to \$1.5 billion outstanding at any one time in commercial paper and other unsecured short-term debt were as follows:

- Utah Public Service Commission (the "UPSC") - Docket No. 06-035-027, Report and Order dated March 17, 2006
- Oregon Public Utility Commission (the "OPUC") - Docket No. UF-4120 and Order No. 98-158 dated April 16, 1998
- Washington Utilities and Transportation Commission (the "WUTC") - Docket No. UE-980404 dated April 8, 1998
- Idaho Public Utilities Commission (the "IPUC") - Case No. PAC-E-06-01 and Order No. 29999 dated March 14, 2006
- United States Securities and Exchange Commission (the "SEC") - Release No. 35-27851 dated May 28, 2004; filed with the FERC on February 6, 2006, pursuant to 18 CFR 366.6(b)

Long-Term Debt

In January 2008, PacifiCorp received regulatory authority from the OPUC and the IPUC to issue up to an additional \$2.0 billion of long-term debt. PacifiCorp must make a notice filing with the WUTC prior to any future issuance. Also in January 2008, PacifiCorp filed a shelf registration statement with the SEC covering future first mortgage bond issuances. In May 2007, PacifiCorp was granted an exemption from obtaining written approval from the UPSC prior to the issuance of securities. The exemption generally remains in effect as long as PacifiCorp's senior secured debt maintains investment grade ratings.

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PacifiCorp			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

In October 2007, PacifiCorp issued \$600 million of its 6.25% First Mortgage Bonds due October 15, 2037. State commission authorizations for this issuance were as follows:

- OPUC - Docket No. UF-4237 and Order No. 07-085 dated March 5, 2007
- IPUC - Case No. PAC-E-07-02 and Order No. 30258 dated February 27, 2007

In March 2007, PacifiCorp issued \$600 million of its 5.75% First Mortgage Bonds due April 1, 2037. State commission authorizations for this issuance were as follows:

- UPSC - Docket No. 07-035-05, Report and Order dated March 2, 2007
- OPUC - Docket No. UF-4237 and Order No. 07-085 dated March 5, 2007
- WUTC - Docket No. UE-070450 and Order No. 1 dated March 7, 2007
- IPUC - Case No. PAC-E-07-2 and Order No. 30258 dated February 27, 2007

Revolving Credit and Other Financing Arrangements

At December 31, 2007, PacifiCorp had \$1.5 billion available under its unsecured revolving credit facilities. During the year ended December 31, 2007, PacifiCorp entered into an unsecured revolving credit facility with total bank commitments of \$700 million available through October 23, 2012. Under PacifiCorp's existing unsecured revolving credit facility, \$800 million is available through July 6, 2011 and \$760 million is available from July 7, 2011 through July 6, 2012. The bank facilities support PacifiCorp's commercial paper program and include a variable interest rate borrowing option based on the London Interbank Offered Rate ("LIBOR"), plus a margin that is currently 0.195%, and varies based on PacifiCorp's credit ratings for its senior unsecured long-term debt securities. At December 31, 2007, PacifiCorp did not have any borrowings outstanding under either credit facility.

At December 31, 2007, PacifiCorp had \$518 million of standby letters of credit and standby bond purchase agreements available to provide credit enhancement and liquidity support for variable-rate pollution-control revenue bond obligations. These committed bank arrangements were fully available at December 31, 2007 and expire periodically through May 2012.

In addition, at December 31, 2007, PacifiCorp had approximately \$18 million of standby letters of credit available to provide credit support for certain transactions as requested by third parties. These committed bank arrangements were all fully available at December 31, 2007 and have provisions that automatically extend the annual expiration dates for an additional year unless the issuing bank elects not to renew a letter of credit prior to the expiration date.

PacifiCorp's revolving credit and other financing agreements contain customary covenants and default provisions, including a covenant not to exceed a specified debt-to-capitalization ratio of 0.65 to 1.0. At December 31, 2007, PacifiCorp was in compliance with the covenants of its revolving credit and other financing agreements.

ITEM 7.

Changes in Articles of Incorporation or Amendments to Charter

None.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
PacifiCorp			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

ITEM 8.

Estimated Annual Effect of Wage Scale Changes

PacifiCorp's bargaining unit wage scale changes were as follows:

Unions Represented	% Increase (a)	Effective Date(s)	Estimated Annual Financial Impact (b)(c)
IBEW 57 Power Delivery (UT, ID & WY)	2.78%	1/26/2007	\$ 2,127,000
IBEW 127 (WY)	2.82%	3/26/2007 & 9/26/2007	1,107,000
IBEW 57 Generation (UT, ID & WY)	2.79%	1/26/2007	978,000
Total			\$ 4,212,000

- (a) This percentage increase represents the increase in wages for all effective dates during the calendar year as compared to the wage scale of the prior effective period.
- (b) Some amounts may be reimbursed by joint owners of steam generating facilities.
- (c) The estimated annual impact is based on the time period from the effective date of the increase to the end of the calendar year.

ITEM 9.

Legal Proceedings

In addition to the proceedings described below, PacifiCorp is currently party to various items of litigation or arbitration in the normal course of business, none of which are reasonably expected by PacifiCorp to have a material adverse effect on its financial results.

In December 2007, PacifiCorp was served with a complaint filed in the United States District Court for the Northern District of California by the Klamath Riverkeeper (a local environmental group); Leaf Hillman (a Karuk Tribe member); Howard McConnell and Robert Attebery (Yurok Tribe members); and Blythe Reis (a resort owner). The complaint alleged that reservoirs behind the hydroelectric dams that PacifiCorp operates on the Klamath River provide an environment for the growth of a blue-green algae known as microcystis aeruginosa, which can generate a toxin called microcystin. The complaint alleged that such algae is a "solid waste" under the federal Resource Conservation and Recovery Act, that PacifiCorp "generates" and "stores" such algae in its reservoirs, that PacifiCorp "disposes" of such algae when it passes through the dams, and that such "generation," "storage" and "disposal" causes or threatens to cause an imminent and substantial endangerment to health and the environment. PacifiCorp believed the claims to be without merit and filed a motion to dismiss in December 2007. In February 2008, a court order was issued conditionally allowing the consolidation of the December 2007 blue-green algae case with the May 2007 blue-green algae case described below, provided that plaintiffs agree to pay PacifiCorp for certain delay costs caused by the consolidation. Plaintiffs did not agree to pay PacifiCorp's delay costs and the court subsequently issued an order to dismiss the lawsuit in March 2008.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
PacifiCorp			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

In May 2007, PacifiCorp was served with a complaint filed in the United States District Court for the Northern District of California by Leaf Hillman and Terance J. Supahan (Karuk Tribe members); Frankie Joe Myers, Howard McConnell and Robert Attebery (Yurok Tribe members); Michael T. Hudson (a commercial fisherman); Blythe Reis (a resort owner); and the Klamath Riverkeeper (a local environmental group) alleging that toxic algae "introduced" by PacifiCorp into Klamath hydroelectric project reservoirs is released by PacifiCorp to the river downstream of the project, and caused or will cause the plaintiffs physical, property, and economic harm. Plaintiffs allege seven causes of action based on nuisance, trespass, negligence, and unlawful business practices, all under California law. Elevated concentrations of microcystis aeruginosa (blue-green algae) have been identified in Klamath River hydroelectric project reservoirs, and now farther downstream on the Klamath River. The algae occur naturally across Oregon, California, and throughout the world. Elevated concentrations tend to appear in areas of slack water that is relatively warm. It has been identified for years on Klamath Lake. Plaintiffs seek unspecified damages and injunctive relief; however, in an order filed by the court in August 2007, the court dismissed plaintiffs' claims for injunctive relief based on federal preemption under the Federal Power Act. Additionally, in March 2008, plaintiff Robert Attebery voluntarily dismissed his claims in the case, and on April 2, 2008, the court entered a stipulation and order dismissing plaintiff Klamath Riverkeeper's claims, with prejudice. PacifiCorp denies the allegations and is vigorously defending the case, which is currently in the discovery phase.

In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a complaint against PacifiCorp in the federal district court in Cheyenne, Wyoming, alleging violations of Wyoming state opacity standards at PacifiCorp's Jim Bridger plant in Wyoming. Under Wyoming state requirements, which are part of the Jim Bridger plant's Title V permit and are enforceable by private citizens under the federal Clean Air Act, a potential source of pollutants such as a coal-fired generating facility must meet minimum standards for opacity, which is a measurement of light that is obscured in the flue of a generating facility. The complaint alleges thousands of violations of asserted six-minute compliance periods and seeks an injunction ordering the Jim Bridger plant's compliance with opacity limits, civil penalties of \$32,500 per day per violation, and the plaintiffs' costs of litigation. The court granted a motion to bifurcate the trial into separate liability and remedy phases. A five-day trial on the liability phase is scheduled to begin in April 2008. The remedy-phase trial has not yet been set. The court is considering several summary judgment motions filed by the parties, but has not yet ruled on any of them. PacifiCorp believes it has a number of defenses to the claims. PacifiCorp intends to vigorously oppose the lawsuit but cannot predict its outcome at this time. PacifiCorp has already committed to invest at least \$812 million in pollution control equipment at its generating facilities, including the Jim Bridger plant. This commitment is expected to significantly reduce system-wide emissions, including emissions at the Jim Bridger plant.

In October 2005, PacifiCorp was added as a defendant to a lawsuit originally filed in February 2005 in state district court in Salt Lake City, Utah by USA Power, LLC and its affiliated companies, USA Power Partners, LLC and Spring Canyon, LLC (collectively, "USA Power"), against Utah attorney Jody L. Williams and the law firm Holme, Roberts & Owen, LLP, who represent PacifiCorp on various matters from time to time. USA Power is the developer of a planned generation project in Mona, Utah called Spring Canyon, which PacifiCorp, as part of its resource procurement process, at one time considered as an alternative to the Currant Creek plant. USA Power's complaint alleged that PacifiCorp misappropriated confidential proprietary information in violation of Utah's Uniform Trade Secrets Act and accused PacifiCorp of breach of contract and related claims. USA Power seeks \$250 million in damages, statutory doubling of damages for its trade secrets violation claim, punitive damages, costs and attorneys' fees. After considering various motions for summary judgment, the court ruled in October 2007 in favor of PacifiCorp on all counts and dismissed the plaintiffs' claims in their entirety. Plaintiffs are expected to appeal this decision and PacifiCorp believes that its defenses that prevailed in the trial court will prevail on appeal. Furthermore, PacifiCorp expects that the outcome of any appeal will not have a material impact on its financial results.

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PacifiCorp			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

In May 2004, PacifiCorp was served with a complaint filed in the United States District Court for the District of Oregon by the Klamath Tribes of Oregon, individual Klamath Tribal members and the Klamath Claims Committee. The complaint generally alleges that PacifiCorp and its predecessors affected the Klamath Tribes' federal treaty rights to fish for salmon in the headwaters of the Klamath River in southern Oregon by building dams that blocked the passage of salmon upstream to the headwaters beginning in 1911. In September 2004, the Klamath Tribes filed their first amended complaint adding claims of damage to their treaty rights to fish for sucker and steelhead in the headwaters of the Klamath River. The complaint seeks in excess of \$1.0 billion in compensatory and punitive damages. In July 2005, the District Court dismissed the case and in September 2005 denied the Klamath Tribes' request to reconsider the dismissal. In October 2005, the Klamath Tribes appealed the District Court's decision to the Ninth Circuit and briefing was completed in March 2006. In February 2008, the Ninth Circuit affirmed the District Court's decision. The plaintiffs in the case may seek rehearing before a larger panel on the Ninth Circuit or appeal to the U.S. Supreme Court. PacifiCorp believes the outcome of this proceeding will not have a material impact on its financial results.

ITEM 10.

None.

ITEM 11.

(Reserved)

ITEM 12.

Federal Regulatory Matters

For a discussion of California and Northwest Refund cases, refer to Note 11 of Notes to Financial Statements included in this Form 1.

The Bonneville Power Administration Residential Exchange Program

The Northwest Power Act, through the Residential Exchange Program, provides access to the benefits of low-cost federal hydroelectricity to the residential and small-farm customers of the region's investor-owned utilities. The program is administered by the Bonneville Power Administration (the "BPA") in accordance with federal law. Pursuant to agreements between the BPA and PacifiCorp, benefits from the BPA are passed through to PacifiCorp's Oregon, Washington and Idaho residential and small-farm customers in the form of electricity bill credits. In October 2000, PacifiCorp entered into a settlement agreement with the BPA that provided Residential Exchange Program benefits to PacifiCorp's customers from October 2001 through September 2006. In May 2001, PacifiCorp entered into a load reduction agreement with the BPA that eliminated the BPA's obligation to deliver power to PacifiCorp from October 2001 through September 2006 in exchange for cash payments. This agreement also contained a "reduction of risk discount" provision, which provided that the BPA would reduce the cash payments to PacifiCorp if by December 1, 2001, PacifiCorp and other utilities were able to negotiate and enter into settlement agreements with the publicly owned utilities and other of the BPA's preference customers dismissing certain lawsuits. If these parties did not reach settlement by the specified date, the clause would expire and the BPA would make cash payments to PacifiCorp based on the original rate for the October 2002 through September 2006 period. Settlement was not reached and the clause expired, obligating the BPA to make the full cash payment to PacifiCorp. In May 2004, PacifiCorp, the BPA and other parties executed an additional agreement, which modified both the October 2000 and May 2001 agreements, which provides for a guaranteed range of benefits to customers from October 2006 through September 2011.

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PacifiCorp			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

Several publicly owned utilities, cooperatives and the BPA's direct-service industry customers filed lawsuits against the BPA with the United States Court of Appeals for the Ninth Circuit (the "Ninth Circuit") seeking review of certain aspects of the BPA's Residential Exchange Program, as well as challenging the level of benefits previously paid to investor-owned utility customers. In May 2007, the Ninth Circuit issued two decisions. The first decision sets aside the October 2000 Residential Exchange Program settlement agreement as being inconsistent with the BPA's settlement authority. The second decision holds, among other things, that the BPA acted contrary to law when it allocated to its preference customers, which include public utilities, cooperatives and federal agencies, part of the costs of the October 2000 settlement the BPA reached with its investor-owned utility customers. As a result of the ruling, in May 2007, the BPA notified the Pacific Northwest's six utilities, including PacifiCorp, that it was immediately suspending payments. This has resulted in increases to PacifiCorp's residential and small-farm customers' electric bills in Oregon, Washington and Idaho. In October 2007, the Ninth Circuit issued one published decision and three unpublished decisions. The published decision remanded the May 2004 agreement modifying the October 2000 and May 2001 agreements to the BPA for further action consistent with the Ninth Circuit's May 2007 decisions. The other three unpublished decisions dismiss cases in which the publicly owned utilities sought review of the BPA's decision to implement the reduction of risk discount provision and make the full cash payment to PacifiCorp. In February 2008, the BPA initiated a rate proceeding under section 7(i) of the Northwest Power Act to reconsider the level of benefits for the years 2002 through 2006 consistent with the Ninth Circuit's decisions, to re-establish the level of benefits for years 2007 and 2008 and to set the level of benefits for years 2009 and beyond. Because the benefit payments from the BPA are passed through to PacifiCorp's customers, the outcome of this matter is not expected to have a significant effect on PacifiCorp's financial results.

FERC Market Oversight

FERC Order No. 693

In March 2007, the FERC issued Order No. 693, *Mandatory Reliability Standards for the Bulk-Power System*, which imposes penalties of up to \$1 million per day per violation for failure to comply with new electric reliability standards. The FERC approved 83 reliability standards developed by the North American Electric Reliability Corporation (the "NERC"). Responsibility for compliance and enforcement of these standards has been given to the WECC. The 83 standards comprise over 600 requirements and sub-requirements with which PacifiCorp must comply. On June 18, 2007, the standards became mandatory and enforceable under federal law. PacifiCorp expects that the existing standards will change as a result of modifications, guidance and clarification following industry implementation and ongoing audits and enforcement. On January 18, 2008, the FERC approved eight additional cyber security and critical infrastructure protection standards proposed by the NERC. The additional standards will become effective on April 7, 2008. PacifiCorp cannot predict the effect that these standards will have on its financial results; however, they will likely have a significant impact on transmission operations and resource planning functions. Also during 2007, the WECC audited PacifiCorp's compliance with several of the reliability standards approved by the FERC. PacifiCorp is analyzing the preliminary results of the audit and, at this time, cannot predict the impact of potential penalties, if any, on its financial results.

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PacifiCorp			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

FERC Orders No. 890 and 890-A

In February 2007, the FERC adopted a final rule in Order No. 890 designed to strengthen the pro forma OATT by providing greater specificity and increasing transparency. The most significant revisions to the pro forma OATT relate to the development of more consistent methodologies for calculating available transfer capability, changes to the transmission planning process, changes to the pricing of certain generator and energy imbalances to encourage efficient scheduling behavior and to exempt intermittent generators, and changes regarding long-term point-to-point transmission service, including the addition of conditional firm long-term point-to-point transmission service, and generation re-dispatch. As a transmission provider with an open-access transmission tariff on file with the FERC, PacifiCorp is required to comply with the requirements of the new rule. The first compliance filing, which amends the OATT, was filed in July 2007. Certain details related to the precise methodology that will be used to calculate available transfer capability were filed with the FERC in September 2007. A number of parties to the proceeding, including PacifiCorp, have requested rehearing or clarification of various portions of the final rule. In December 2007, the FERC issued Order No. 890-A generally affirming the provisions of the final rule as adopted in Order No. 890 with certain limited clarifications. Although PacifiCorp has requested a limited clarification of Order No. 890-A, the final rule as revised is not anticipated to have a significant impact on PacifiCorp's financial results, but it will likely have a significant impact on its transmission operations, planning and wholesale marketing functions.

Energy Policy Act of 2005

On August 8, 2005, the Energy Policy Act was signed into law and has significantly impacted the energy industry. In particular, the law expanded the FERC's regulatory authority in areas such as electric system reliability, electric transmission expansion and pricing, regulation of utility holding companies, and enforcement authority to issue civil penalties of up to \$1 million per day. While the FERC has now issued rules and decisions on multiple aspects of the Energy Policy Act, the full impact of those decisions remains uncertain.

The Energy Policy Act also gives the FERC "backstop" transmission siting authority and directs the FERC to oversee the establishment of mandatory transmission reliability standards as discussed above. The Energy Policy Act also extended the federal production tax credit for new renewable electricity generation projects through December 31, 2007, with subsequent legislation extending the credit to December 31, 2008. Partly as a result of that portion of the law, PacifiCorp began development efforts for additional wind plants.

Transmission Settlement

In January 2007, the FERC approved a settlement with PacifiCorp regarding PacifiCorp's use of its transmission system while conducting wholesale power transactions with third parties. PacifiCorp discovered possible violations of its FERC-approved tariff during an internal investigation of its compliance with certain FERC regulations shortly before MidAmerican Energy Holdings Corporation's ("MEHC") acquisition of PacifiCorp. Upon completion of the acquisition, PacifiCorp self-reported the potential violations to the FERC. The potential violations primarily related to the way PacifiCorp used its own transmission system to transmit energy using "network service" instead of "point-to-point" service as the FERC believes is required by PacifiCorp's tariff. This use of transmission service neither enriched PacifiCorp's shareholders nor harmed its retail customers. As part of the settlement, PacifiCorp voluntarily refunded \$1 million to other transmission customers in April 2006 and paid a \$10 million fine to the United States Treasury in January 2007.

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IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

Wholesale Electricity and Capacity

The FERC regulates PacifiCorp's rates charged to wholesale customers for electricity, capacity and transmission services. Most of PacifiCorp's electric wholesale sales and purchases take place under market-based rate pricing allowed by the FERC and are therefore subject to market volatility. A December 2006 decision of the Ninth Circuit changed the interpretation of the relevant standard that the FERC should apply when reviewing wholesale contracts for electricity or capacity from a stringent "public policy" standard to a broader "just and reasonable" standard making contracts more vulnerable to challenge. The decision raises some concerns regarding the finality of contract prices, particularly from the sellers' side of the transactions. The United States Supreme Court is reviewing the case on appeal and the outcome of its ruling cannot be predicted at this time. All sellers subject to the FERC's jurisdiction, including PacifiCorp, are currently subject to increased risk as a result of this decision.

The FERC conducts a triennial review of PacifiCorp's market-based rate pricing authority. Each utility must demonstrate the lack of generation market power in order to charge market-based rates for sales of wholesale electricity and capacity in their respective balancing authority areas. Under the FERC's market-based rules, PacifiCorp must file a notice of change in status when 100 MW of incremental generation becomes operational. Following separate filings by PacifiCorp of a change in status notice relating to new generation, the FERC in February and November 2007 confirmed that PacifiCorp does not have market power and may continue to charge market-based rates. In accordance with the filing schedule established by the FERC in Order No. 697, PacifiCorp's next triennial review will occur in 2010 or earlier if required.

Hydroelectric Relicensing

Several of PacifiCorp's hydroelectric plants are in some stage of the relicensing process with the FERC. PacifiCorp also has requested the FERC to allow decommissioning of certain hydroelectric projects. The following summarizes the status of certain of these projects.

Klamath Hydroelectric Project – (Klamath River, Oregon and California)

In February 2004, PacifiCorp filed with the FERC a final application for a new license to operate the 169-MW (nameplate rating) Klamath hydroelectric project in anticipation of the March 2006 expiration of the existing license. PacifiCorp is currently operating under an annual license granted by the FERC and expects to continue to operate under annual licenses until the new operating license is issued. As part of the relicensing process, the United States Departments of Interior and Commerce filed proposed licensing terms and conditions with the FERC in March 2006, which proposed that PacifiCorp construct upstream and downstream fish passage facilities at the Klamath hydroelectric project's four mainstem dams. In April 2006, PacifiCorp filed alternatives to the federal agencies' proposal and requested an administrative hearing to challenge some of the federal agencies' factual assumptions supporting their proposal for the construction of the fish passage facilities. A hearing was held in August 2006 before an administrative law judge. The administrative law judge issued a ruling in September 2006 generally supporting the federal agencies' factual assumptions. In January 2007, the United States Departments of Interior and Commerce filed modified terms and conditions consistent with March 2006 filings and rejected the alternatives proposed by PacifiCorp. PacifiCorp is prepared to meet and implement the federal agencies' terms and conditions as part of the project's relicensing. However, PacifiCorp expects to continue in settlement discussions with various parties in the Klamath Basin area who have intervened with the FERC licensing proceeding to try to achieve a mutually acceptable outcome for the project.

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IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

Also, as part of the relicensing process, the FERC is required to perform an environmental review. In September 2006, the FERC issued its draft environmental impact statement on the Klamath hydroelectric project license. PacifiCorp filed comments on the draft statement by the close of the public comment period on December 1, 2006. Subsequently, in November 2007, the FERC issued its final environmental impact statement. The United States Fish and Wildlife Service and the National Marine Fisheries Service issued final biological opinions in December 2007 analyzing the hydroelectric project's impact on endangered species under the proposed new FERC license. The United States Fish and Wildlife Service asserts the hydroelectric project is currently not covered by previously issued biological opinions, and that consultation under the Endangered Species Act is required by the issuance of annual license renewals. PacifiCorp disputes these assertions, and believes federal case law is clear that consultation on annual FERC licenses is not required. PacifiCorp will need to obtain water quality certifications from Oregon and California prior to the FERC issuing a final license. PacifiCorp currently has applications pending before each state.

Lewis River Hydroelectric Projects – (Lewis River, Washington)

PacifiCorp filed new license applications for the 136-MW (nameplate rating) Merwin and 240-MW (nameplate rating) Swift No. 1 hydroelectric projects in April 2004. An application for a new license for the 134-MW (nameplate rating) Yale hydroelectric project was filed with the FERC in April 1999. However, consideration of the Yale application was delayed pending filing of the Merwin and Swift No. 1 applications so that the FERC could complete a comprehensive environmental analysis.

In November 2004, PacifiCorp executed a comprehensive settlement agreement with 25 other parties including state and federal agencies, Native American tribes, conservation groups, and local government and citizen groups to resolve, among the parties, issues related to the pending applications for new licenses for PacifiCorp's Merwin, Swift No. 1 and Yale hydroelectric projects. As part of this settlement agreement, PacifiCorp agreed to implement certain protection, mitigation and enhancement measures prior to and during a proposed 50-year license period. However, these commitments are contingent on ultimately receiving licenses from the FERC and other required permits that are consistent with the settlement agreement. PacifiCorp has received water quality certificates from the Washington Department of Ecology and biological opinions from the United States Fish and Wildlife Service and the National Marine Fisheries Service. Regulatory documents needed to license the projects have been submitted to the FERC and PacifiCorp is awaiting the issuance of new FERC licenses.

Prospect Hydroelectric Project – (Rogue River, Oregon)

In June 2003, PacifiCorp submitted a final license application to the FERC for the Prospect Nos. 1, 2 and 4 hydroelectric projects, whose nameplate ratings total 37 MW. The Oregon Department of Environmental Quality issued a 401 Water Quality certificate for the project in April 2007, which effectively concluded the license process. The FERC is expected to issue a new license before the end of May 2008.

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PacifiCorp			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

Hydroelectric Decommissioning

Powerdale Hydroelectric Project – (Hood River, Oregon)

In June 2003, PacifiCorp entered into a settlement agreement to remove the 6-MW (nameplate rating) Powerdale plant rather than pursue a new license, based on an analysis of the costs and benefits of relicensing versus decommissioning. Removal of the Powerdale dam and associated project features, which is subject to the FERC and other regulatory approvals, is projected to cost \$6 million excluding inflation. Removal was scheduled to commence in 2010. However, in November 2006, flooding damaged the Powerdale plant and rendered its generating capabilities inoperable. In February 2007, the FERC granted PacifiCorp's request to cease generation at the project until decommissioning activities begin. Also in February 2007, PacifiCorp submitted a request to the FERC to allow the company to defer the remaining net book value and any additional removal costs of this project as a regulatory asset. In May 2007, the FERC issued an order that approved PacifiCorp's proposed accounting entries, thereby allowing PacifiCorp to reclassify the net book value and the estimated removal costs to a regulatory asset. PacifiCorp has received approval from its state commissions to defer and recover these costs.

Condit Hydroelectric Project – (White Salmon River, Washington)

In September 1999, a settlement agreement to remove the 10-MW (nameplate rating) Condit hydroelectric project was signed by PacifiCorp, state and federal agencies and non-governmental organizations. Under the original settlement agreement, removal was expected to begin in October 2006, with a total cost to decommission not to exceed \$17 million, excluding inflation. In early February 2005, the parties agreed to modify the settlement agreement so that removal will not begin until October 2008 for a total cost to decommission not to exceed \$21 million, excluding inflation. The settlement agreement is contingent upon receiving a FERC surrender order and other regulatory approvals that are not materially inconsistent with the amended settlement agreement. PacifiCorp is in the process of acquiring all necessary permits, within the terms and conditions of the amended settlement agreement. If the permitting process continues into the second quarter of 2008, the decommissioning will not begin until October 2009.

Cove Hydroelectric Project – (Bear River, Idaho)

In May 2006, the FERC approved PacifiCorp's application to amend the Bear River license and authorized the removal of the 8-MW (nameplate rating) Cove hydroelectric plant and facilities. Decommissioning of the Cove facilities has been completed in accordance with the license amendment and the approved removal plan. The removal of the dam, flowline and all facilities, with the exception of the powerhouse that has been designated a historical landmark, was completed in November 2006. As of December 31, 2007, \$3 million had been spent for the decommissioning of the Cove hydroelectric project.

American Fork Hydroelectric Project – (American Fork Creek, Utah)

In August 2004, the FERC authorized the removal of the 1-MW (nameplate rating) American Fork hydroelectric plant and facilities. Decommissioning of the American Fork facilities has been completed in accordance with the approved removal plan. The removal of the dam, flowline and all facilities, with the exception of the powerhouse that has been designated a historical landmark, was completed in December 2007. As of December 31, 2007, \$4 million had been spent for the decommissioning of the American Fork hydroelectric project.

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PacifiCorp			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

United States Mine Safety

Mining operations are regulated by the federal Mine Safety and Health Administration ("MSHA"), which administers federal mine safety and health laws, regulations and state regulatory agencies. The Mine Improvement and New Emergency Response Act of 2006 ("MINER Act"), enacted in June 2006, amended previous mine safety and health laws to improve mine safety and health and accident preparedness. The MINER Act, portions of which are not yet fully implemented, requires operators of underground coal mines to develop a written emergency response plan specific to each mine they operate. These plans must be reviewed by MSHA every six months. It also requires every mine to have at least two rescue teams located within one hour, and it limits the legal liability of rescue team members and the companies that employ them. The MINER Act also increases civil and criminal penalties for violations of federal mine safety standards and gives MSHA the ability to institute a civil action for relief, including a temporary or permanent injunction, restraining order or other appropriate order against a mine operator who fails to pay the penalties or fines.

State Regulatory Actions

PacifiCorp is currently pursuing a regulatory program in all states, with the objective of keeping rates closely aligned to ongoing costs. The following discussion provides a state-by-state update.

Utah

In December 2007, PacifiCorp filed a general rate case with the UPSC requesting an annual increase of \$161 million, or an average price increase of 11%. The increase is primarily due to increased capital spending and net power costs, both of which are driven by load growth. In February 2008, the UPSC issued an order determining that the proper test period should end December 2008. In March 2008, PacifiCorp filed supplemental testimony reducing the requested rate increase to \$100 million. The six month change in the test period accounts for \$40 million of the reduction. The supplemental filing also reflects an additional \$21 million of reductions associated with recent UPSC orders on depreciation rates and two deferred accounting requests that were pending when the original case was filed. Hearings on the revenue requirement portion of the case are scheduled for June 2008, with the rate-design phase scheduled for October 2008. PacifiCorp expects that initial rates, if approved, will become effective no later than August 2008.

In December 2006, the UPSC approved a stipulation settling PacifiCorp's general rate case filed in March 2006 related to increased investments in Utah due to growing demand for electricity. The stipulation called for an annual increase of \$115 million, or an average price increase of 10%, with \$85 million of the increase effective December 11, 2006 and the remaining \$30 million increase effective June 1, 2007.

Oregon

In April 2008, PacifiCorp filed its net power costs for 2009 in the company's Transition Adjustment Mechanism (the "TAM") and revenue requirement for 2009 for new renewable resources in the Renewable Adjustment Clause (the "RAC"). The TAM and the RAC filings propose a combined rate increase of \$80 million, or 9%, effective January 1, 2009. The combined increase is 7% to residential customers and 12% to industrial customers. Although PacifiCorp will make two separate filings, it is expected that the filings will be consolidated into one proceeding. The filings are complementary in that if the fixed costs of an eligible resource are included in the RAC or otherwise in rates, then the variable costs and cost offsets of the resource are included in the TAM. Both mechanisms are designed to produce a commission decision by November 2008.

In August 2007, PacifiCorp filed a renewable cost adjustment clause that will allow for timely recovery between rate cases of the costs of eligible renewable resources and associated transmission under the renewable portfolio standards ("RPS"). The RPS required the OPUC to approve an automatic adjustment clause for timely recovery of these costs by January 1, 2008. In December 2007, the OPUC approved a settlement stipulation filed by the parties to the proceedings that established the RAC mechanism, with an effective date of January 1, 2008. Under the RAC mechanism, PacifiCorp will submit a filing on April 1 of each year, with rates to become effective January 1 of the following year, to recover the revenue requirement of new renewable resources and associated transmission that are not reflected in general rates. As part of the RAC mechanism, the OPUC authorized PacifiCorp to defer eligible costs not yet included in rates until the next annual RAC filing.

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In July 2007, as part of PacifiCorp's annual compliance filing with the OPUC to update forecasted net power costs, PacifiCorp requested an increase of approximately \$30 million, or an average price increase of 3%, to take effect January 1, 2008. The annual filing, called the transition adjustment mechanism ("TAM"), was adjusted for new contracts through October 2007 and for other changes to forecasted net power costs, such as coal and natural gas prices, through November 2007. In October 2007, the OPUC issued an order that approved the TAM increase subject to PacifiCorp updating its net power cost forecast to reflect changes adopted in the decision. In November 2007, PacifiCorp submitted a compliance filing with an updated net power cost forecast, which reflected a \$22 million increase, or an average price increase of 2%. In December 2007, the OPUC approved the TAM with rates effective January 1, 2008.

In September 2006, the OPUC approved a settlement agreement resolving PacifiCorp's February 2006 general rate case request related to investments in generation, transmission and distribution infrastructure and increases in fuel and general operating expenses, including the maintenance of low-cost but aging power plants. Pursuant to the settlement agreement, PacifiCorp received an annual increase for non-power cost items of \$33 million effective January 1, 2007. Also on January 1, 2007, PacifiCorp received a \$10 million increase for power costs through its annual TAM.

For a discussion of Oregon Senate Bill 408, refer to Note 3 of Notes to Financial Statements included in this Form 1.

Wyoming

In June 2007, PacifiCorp filed a general rate case with the Wyoming Public Service Commission (the "WPSC") requesting an annual increase of \$36 million, or an average price increase of 8%. In addition, PacifiCorp requested approval of a new renewable resource recovery mechanism and a marginal cost pricing tariff to better reflect the cost of adding new generation. In January 2008, PacifiCorp reached a settlement in principle with parties to the case, subject to entering into a final stipulation and approval by the WPSC. The settlement provides for an annual rate increase of \$23 million, or an average price increase of 5%. In addition, the parties also agreed to a forecast power cost mechanism and discontinuation of the current power cost adjustment mechanism ("PCAM") by April 2011, unless a continuation is specifically applied for by PacifiCorp and approved by the WPSC. PacifiCorp's marginal cost pricing tariff proposal will not be implemented, but will be the subject of a collaborative process to seek a new pricing proposal. Also as part of the settlement, PacifiCorp agreed to withdraw from this filing its request for a renewable resource recovery mechanism. The stipulation was executed and filed with the WPSC in January 2008 and was the subject of a hearing for approval in March 2008 where it was approved. The new rates will become effective May 1, 2008.

In February 2008, PacifiCorp filed its annual deferred net power cost adjustment application with the WPSC in the amount of \$31 million for costs incurred during the period December 1, 2006 through November 30, 2007.

In February 2007, PacifiCorp filed its first annual deferred net power cost adjustment application with the WPSC in the amount of \$3 million for costs incurred during the period July 1, 2006 through November 30, 2006. In March 2007, PacifiCorp received approval from the WPSC to implement interim rates effective April 1, 2007, in the amount of \$3 million. In May 2007, PacifiCorp filed a stipulation and agreement with the WPSC that resolved all issues in the application and reduced the deferred net power cost adjustment to \$2 million. The revised rates were effective July 1, 2007.

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PacifiCorp			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

Washington

In February 2008, PacifiCorp filed a general rate case with the WUTC for an annual increase of \$35 million, or an average price increase of 15%, with an effective date no later than January 2009.

In October 2006, PacifiCorp filed a general rate case with the WUTC for an annual increase of \$23 million, or an average price increase of 10%. As part of the filing, PacifiCorp proposed a Washington-only cost-allocation methodology, which is based on PacifiCorp's western resources. The rate case included a five-year pilot period on the proposed allocation methodology and a PCAM. In June 2007, the WUTC issued an order approving a rate increase of \$14 million, or an average price increase of 6%, effective June 27, 2007, and accepted PacifiCorp's proposed western balancing authority area cost-allocation methodology for a five-year pilot period. The WUTC found that PacifiCorp demonstrated the need for a PCAM, but it did not approve the design of the proposal in this case. The order authorized PacifiCorp to file a revised PCAM proposal, with or without a request to file power cost-only rate cases, outside the context of a general rate case within 12 months of the order.

Idaho

In June 2007, PacifiCorp filed a general rate case with the IPUC for an annual increase of \$18 million, or an average price increase of 10%, with a request for an effective date of January 1, 2008. In November 2007, an all-party stipulation was reached on all issues in the general rate case, resulting in an annual increase of \$12 million, or an average price increase of 6%. The IPUC approved the settlement stipulation in December 2007, with new rates effective January 1, 2008. The settlement also provides for rate increases effective January 1, 2009 and 2010 for PacifiCorp's two special contract industrial customers and no additional rate changes for those two special contract customers effective prior to January 1, 2011. Additional rate increases for the remaining customer classes may be requested if needed to maintain cost of service coverage.

California

In October 2007, PacifiCorp filed two advice letters requesting authority to implement components of the post test-year adjustment mechanism ("PTAM"), a mechanism that allows for annual rate adjustments for changes in operating costs and plant additions outside of the context of a traditional rate case. The combined requested increase totaled \$2 million, or an average price increase of 2%. The California Public Utilities Commission (the "CPUC") approved the increase in November 2007. In December 2007, PacifiCorp revised the increase based on updated capital additions, and the CPUC issued a revised order for a \$1 million increase, or an average price increase of 1% effective January 1, 2008.

In August 2007, PacifiCorp filed an energy cost adjustment clause application with the CPUC to update actual and forecasted net variable power costs, requesting a rate increase of \$6 million, or an average price increase of 8%, with an effective date of January 1, 2008. In December 2007, the CPUC issued an order for a \$5 million increase, or an average price increase of 7%, with an effective date of January 1, 2008.

Depreciation Rate Changes

In August 2007, PacifiCorp filed applications with the regulatory commissions in Utah, Oregon, Wyoming, Washington and Idaho to change the rates of depreciation and extend the depreciable lives of certain assets, based on a new depreciation study. Agreements have been reached in each of these states and are in various stages of approval. When approved by the state commissions, the agreements will make the new depreciation rates effective January 1, 2008. For further discussion on depreciation rate changes, refer to Note 2 of the Notes to Financial Statements included in this Form 1.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
PacifiCorp			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

Environmental Regulation

PacifiCorp is subject to federal, state and local laws and regulations with regard to air and water quality, RPS, climate change, hazardous and solid waste disposal and other environmental matters and is subject to zoning and other regulation by local authorities. In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance including fines, injunctive relief and other sanctions. PacifiCorp believes it is in material compliance with all laws and regulations. The most significant environmental laws and regulations affecting PacifiCorp include:

- The federal Clean Air Act, as well as state laws and regulations impacting air emissions, including State Implementation Plans related to existing and new national ambient air quality standards. Rules issued by the Environmental Protection Agency ("EPA") and certain states require substantial reductions in sulfur dioxide and nitrogen oxide emissions beginning in 2009 and extending through 2018. PacifiCorp has already installed certain emission control technology and is taking other measures to comply with required reductions. Refer to "Clean Air Standards" below for additional discussion regarding this topic.
- The federal Water Pollution Control Act ("Clean Water Act") and individual state clean water laws regulate cooling water intake structures and discharges of wastewater, including storm water runoff. PacifiCorp believes that it currently has, or has initiated the process to receive, all required water quality permits. Refer to "Water Quality Standards" below for additional discussion regarding this topic.
- The federal Comprehensive Environmental Response, Compensation and Liability Act and similar state laws, which may require any current or former owners or operators of a disposal site, as well as transporters or generators of hazardous substances sent to such disposal site, to share in environmental remediation costs. Refer to Note 11 of Notes to Financial Statements included in this Form 1 for additional information regarding environmental contingencies.
- The federal Surface Mining Control and Reclamation Act of 1977 and similar state statutes establish operational, reclamation and closure standards that must be met during and upon completion of mining activities.
- The FERC oversees the relicensing of existing hydroelectric projects and is also responsible for the oversight and issuance of licenses for new construction of hydroelectric projects, dam safety inspections and environmental monitoring. Refer to Note 11 of Notes to Financial Statements included in this Form 1 for additional information regarding the relicensing of certain of PacifiCorp's existing hydroelectric facilities.

PacifiCorp is subject to federal, state and local laws and regulations with regard to air and water quality, RPS, climate change, hazardous and solid waste disposal and other environmental matters. The cost of complying with applicable environmental laws, regulations and rules is expected to be material to PacifiCorp. In particular, future mandates may impact the operation of PacifiCorp's generating facilities and may require PacifiCorp to reduce emissions at its generating facilities through the installation of additional emission control equipment or to purchase additional emission allowances or offsets in the future. PacifiCorp is not aware of any established technology that reduces the carbon dioxide emission at coal-fired facilities and PacifiCorp is uncertain when, or if, such technology will be commercially available.

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IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

Expenditures for compliance-related items such as pollution control technologies, replacement generation, mine reclamation, hydroelectric relicensing, hydroelectric decommissioning and associated operating costs are generally incorporated into the routine cost structure of PacifiCorp. An inability to recover these costs from PacifiCorp's customers, either through regulated rates, long-term arrangements or market prices, could adversely affect PacifiCorp's future financial results.

Clean Air Standards

The Clean Air Act provides a framework for protecting and improving the nation's air quality and controlling mobile and stationary sources of air emissions. The major Clean Air Act programs, which most directly affect PacifiCorp's electric generating facilities, are briefly described below. Many of these programs are implemented and administered by the states, which can impose additional, more stringent requirements.

In connection with the March 2006 acquisition of PacifiCorp by MEHC, PacifiCorp committed to state regulators to spend approximately \$812 million over several years to reduce emissions at PacifiCorp's generating facilities to address existing and future air quality requirements. These costs and any additional expenditures necessitated by air quality regulations are expected to be recovered in rates and, as a result, would not have a material adverse impact on PacifiCorp's results of operations. As of December 31, 2007, PacifiCorp had incurred \$205 million in capital expenditures pursuant to this commitment.

National Ambient Air Quality Standards

The EPA implements national ambient air quality standards for ozone and fine particulate matter, as well as for other criteria pollutants that set the minimum level of air quality for the United States. Areas that achieve the standards, as determined by ambient air quality monitoring, are characterized as being in attainment, while those that fail to meet the standards are designated as being nonattainment areas. Generally, sources of emissions in a nonattainment area are required to make emissions reductions. The counties in Washington, Oregon, Montana, Wyoming, Colorado, Utah and Arizona where PacifiCorp's major emission sources are located are in attainment of the current ambient air quality standards. A new, more stringent standard for fine particulate matter became effective on December 18, 2006, but is under legal challenge in the United States Court of Appeals for the District of Columbia Circuit. Air quality modeling and preliminary air quality monitoring data indicate that portions of the states in which PacifiCorp has major emission sources may not meet the new standards. Until three years of data are collected and attainment designations under the new fine particulate standard are made, the impact of these new standards on PacifiCorp will not be known.

On March 12, 2008, the EPA issued a rule to strengthen the ambient air quality standards for ground-level ozone, setting the primary and secondary 8-hour ozone standards to 0.075 parts per million. States will have until June 2009 to characterize their attainment status, with the EPA's determinations regarding non-attainment made by June 2010 and state implementation plans due in 2013. Until the EPA makes its final determination on the revised standards and attainment designations are made, the impact of any new standards on PacifiCorp will not be known. However, based on the new standard, the EPA projects that there may be five counties in Utah that do not meet new standards for ozone.

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IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

Regulated Air Pollutants

In March 2005, the EPA released the final Clean Air Mercury Rule ("CAMR"), a two-phase program that utilizes a market-based cap and trade mechanism to reduce mercury emissions from coal-burning power plants from the 1999 nationwide level of 48 tons to 15 tons. The CAMR required initial reductions of mercury emissions in 2010 and an overall reduction in mercury emissions from coal-burning power plants of 70% by 2018. The individual states in which PacifiCorp operates facilities regulated under the CAMR submitted state implementation plans reflecting their regulations relating to state mercury control programs. On February 8, 2008, the United States Court of Appeals for the District of Columbia Circuit held that the EPA improperly removed electricity generating units from Section 112 of the Clean Air Act and, thus, that the CAMR was improperly promulgated under Section 111 of the Clean Air Act. The court vacated the CAMR's new source performance standards and remanded the matter to the EPA for reconsideration. On March 24, 2008, the EPA filed a petition with the United States Court of Appeals for the District of Columbia Circuit for review *en banc* of the February 8, 2008 decision. In light of this decision, it is not known the extent to which future mercury rules may impact PacifiCorp's current plans to reduce mercury emissions at its coal-fired facilities.

Regional Haze

The EPA has initiated a regional haze program intended to improve visibility at specific federally protected areas. Some of PacifiCorp's plants meet the threshold applicability criteria under the Clean Air Visibility Rules. In accordance with the federal requirements, states were required to submit state implementation plans by December 2007 to demonstrate reasonable progress toward achieving natural visibility conditions in certain Class I areas by requiring emission controls, known as best available retrofit technology, on sources with emissions that are anticipated to cause or contribute to impairment of visibility. Wyoming has not yet submitted its state implementation plan and is continuing to review the results of analyses relating to planned emission reductions at PacifiCorp's Wyoming generating plants. Utah has not yet submitted its state implementation plan, but expects to do so in the near term. PacifiCorp believes that its planned emission reduction projects will satisfy the regional haze requirements in Utah and Wyoming; however, it is possible that some additional controls may be required once the respective state implementation plans have been submitted.

New Source Review

Under existing New Source Review ("NSR") provisions of the Clean Air Act, any facility that emits regulated pollutants is required to obtain a permit from the EPA or a state regulatory agency prior to (i) beginning construction of a new major stationary source of an NSR-regulated pollutant, or (ii) making a physical or operational change to an existing stationary source of such pollutants that increases certain levels of emissions, unless the changes are exempt under the regulations (including routine maintenance, repair and replacement of equipment). In general, projects subject to NSR regulations are subject to pre-construction review and permitting under the Prevention of Significant Deterioration ("PSD") provisions of the Clean Air Act. Under the PSD program, a project that emits threshold levels of regulated pollutants must undergo a "best available control technology" analysis and evaluate the most effective emissions controls. These controls must be installed in order to receive a permit. Violations of NSR regulations, which may be alleged by the EPA, states and environmental groups, among others, potentially subject a utility to material expenses for fines and other sanctions and remedies including requiring installation of enhanced pollution controls and funding supplemental environmental projects.

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IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

As part of an industry-wide investigation to assess compliance with the NSR and PSD provisions, the EPA has requested from numerous utilities information and supporting documentation regarding their capital projects for various generating plants. Between 2001 and 2003, PacifiCorp responded to requests for information relating to its capital projects at its generating plants and has been engaged in periodic discussions with the EPA over several years regarding this matter. An NSR enforcement case against another utility has been decided by the United States Supreme Court, holding that an increase in annual emissions of a facility, when combined with a modification (i.e., a physical or operational change), may trigger NSR permitting. PacifiCorp cannot predict the outcome of the EPA's review of the data it has submitted at this time.

In 2002 and 2003, the EPA proposed various changes to its NSR rules that clarify what constitutes routine repair, maintenance and replacement for purposes of triggering NSR requirements. These changes have been subject to legal challenge, and in March 2006, a panel of the United States Court of Appeals for the District of Columbia Circuit invalidated portions of the EPA's new NSR rules, holding that they conflicted with the wording of the statute. However, the EPA has asked the United States Supreme Court to review portions of the case. Until such time as the legal challenges are resolved and the revised rules are effective, PacifiCorp will continue to manage projects at its generating plants in accordance with the rules in effect prior to 2002, except for pollution-control projects, which are now subject to permitting under the PSD program. In 2005, the EPA proposed a rule that would change or clarify how emission increases are to be calculated for purposes of determining the applicability of the NSR permitting program for existing power plants. The EPA also proposed additional changes to the NSR rules in September 2006 that are intended to simplify the permitting process and allow facilities to undertake activities that improve their safety, reliability and efficiency without triggering NSR requirements. In April 2007, the EPA issued a supplemental notice of proposed rulemaking to determine emissions increases for electric generating units, proposing to use both hourly and annual emissions tests to determine whether utilities trigger the NSR permitting program when an existing power plant makes a physical or operational change. The supplemental proposal was issued three weeks after the United States Supreme Court issued a unanimous opinion in *Environmental Defense v. Duke Energy* that the EPA was correct in applying an annual emissions test to determine NSR compliance.

Renewable Portfolio Standards

The RPS described below could significantly impact PacifiCorp's financial results. Resources that meet the qualifying electricity requirements under the RPS vary from state-to-state. Each state's RPS requires some form of compliance reporting and PacifiCorp can be subject to penalties in the event of non-compliance.

In November 2006, Washington voters approved a ballot initiative establishing a RPS requirement for qualifying electric utilities, including PacifiCorp. The requirements are 3% of retail sales by January 1, 2012 through 2015, 9% of retail sales by January 1, 2016 through 2019 and 15% of retail sales by January 1, 2020. The WUTC has adopted final rules to implement the initiative. PacifiCorp expects to be able to recover its costs of complying with the RPS, either through rate cases or an adjustment mechanism.

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IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

In June 2007, the Oregon Renewable Energy Act (the "Act") was adopted, providing a comprehensive renewable energy policy for Oregon. Subject to certain exemptions and cost limitations established in the Act, PacifiCorp and other qualifying electric utilities must meet minimum qualifying electricity requirements for electricity sold to retail customers of at least 5% in 2011 through 2014, 15% in 2015 through 2019, 20% in 2020 through 2024, and 25% in 2025 and subsequent years. As required by the Act, the OPUC has approved an automatic adjustment clause to allow an electric utility, including PacifiCorp, to recover prudently incurred costs of its investments in renewable energy facilities and associated transmission costs. The OPUC and the Oregon Department of Energy have undertaken additional rulemaking proceedings to further implement the initiative. PacifiCorp expects to be able to recover its costs of complying with the RPS through the automatic adjustment mechanism. For further discussion of the automatic adjustment mechanism, refer to "State Regulatory Actions – Oregon" above.

California law requires electric utilities to increase their procurement of renewable resources by at least 1% of their annual retail electricity sales per year so that 20% of their annual electricity sales are procured from renewable resources by no later than December 31, 2010. However, PacifiCorp and other small multi-jurisdictional utilities ("SMJU") are currently awaiting further guidance from the CPUC on the treatment of SMJUs in the California RPS program. PacifiCorp has filed comments requesting SMJU rules for flexible compliance with annual targets. PacifiCorp expects rules governing the treatment of SMJUs and any specific flexible compliance mechanisms to be released by CPUC staff for public review in early 2008. Absent further direction from the CPUC on treatment of SMJUs, PacifiCorp cannot predict the impact of the California RPS on its financial results.

In March 2008, Utah Governor Huntsman signed Senate Bill 202 ("SB 202"), the Utah "Energy Resource and Carbon Reduction Initiative" bill. SB 202 amends existing law to permit construction of wind projects smaller than 300 megawatts outside the Senate Bill 26 procurement process. It also establishes a target of 20% for PacifiCorp's and other qualifying utilities adjusted retail electric sales in the year 2025 be derived from renewable energy resources, if the renewable resources are determined to be "cost effective". Retail sales will also adjusted by subtracting the non-carbon sources of energy and future carbon sequestration from the total retail sales. The 20% target would then apply to the "carbon" component of PacifiCorp's portfolio. The law also requires: 1) plans and reports concerning progress in acquiring renewable energy and 2) various state agencies to make rules concerning carbon capture and geological storage of captured carbon emissions.

In addition to its portfolio of generating plants, PacifiCorp purchases electricity in the wholesale markets to meet its retail load and long-term wholesale obligations, for system balancing requirements and to enhance the efficient use of its generating capacity over the long term. All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards. For a complete listing of PacifiCorp's purchased electricity, refer to pages 326-327 of this Form No. 1.

Climate Change

As a result of increased attention to global climate change in the United States, numerous bills have been introduced in the current session of the United States Congress that would reduce greenhouse gas emissions in the United States. Congressional leadership has made climate change legislation a priority, and many congressional observers expect to see the passage of climate change legislation within the next several years. The Lieberman-Warner Climate Security Act of 2007 (S. 2191) was passed by the United States Senate Environment and Public Works Committee on December 5, 2007. The bill would impose an economy-wide cap on greenhouse gas emissions to reduce emissions 70% from 2005 levels by 2050. Included within the bill's definition of a covered facility is any facility that uses more than 5,000 tons of coal in a calendar year, which includes all of PacifiCorp's coal-fired generating plants. In addition, nongovernmental organizations have become more active in initiating citizen suits under existing environmental and other laws. In April 2007, a United States Supreme Court decision concluded that the EPA has the authority under the Clean Air Act to regulate emissions of greenhouse gases from motor vehicles. Furthermore, pending cases that address the potential public nuisance from greenhouse gas emissions from electricity generators and the EPA's failure to regulate greenhouse gas emissions from new and existing coal-fired plants are expected to become active. While debate continues at the national level over the direction of domestic climate policy, several states have developed state-specific laws or regional legislative initiatives to reduce greenhouse gas emissions, including:

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IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

- In February 2007, the governors of California, Arizona, New Mexico, Oregon and Washington signed the Western Regional Climate Action Initiative (the "Western Climate Initiative") that directed their respective states to develop a regional target for reducing greenhouse gases by August 2007. Utah joined the Western Climate Initiative in May 2007. The states in the Western Climate Initiative announced a target of reducing greenhouse gas emissions by 15% below 2005 levels by 2020, with Utah establishing its reduction goal by August 2008. By August 2008, they are expected to devise a market-based program, such as a load-based cap-and-trade program for the electricity sector, to reach the regional target. The Western Climate Initiative participants also have agreed to participate in a multi-state registry to track and manage greenhouse gas emissions in the region.
- An executive order signed by California's governor in June 2005 would reduce greenhouse gas emissions in that state to 2000 levels by 2010, to 1990 levels by 2020 and 80% below 1990 levels by 2050. In addition, California has adopted legislation that imposes a greenhouse gas emission performance standard to all electricity generated within the state or delivered from outside the state that is no higher than the greenhouse gas emission levels of a state-of-the-art combined-cycle natural gas generation facility, as well as legislation that adopts an economy-wide cap on greenhouse gas emissions to 1990 levels by 2020.
- The Washington and Oregon governors enacted legislation in May 2007 and August 2007, respectively, establishing economy-wide goals for the reduction of greenhouse gas emissions in their respective states. Washington's goals seek to (i) by 2020, reduce emissions to 1990 levels; (ii) by 2035, reduce emissions to 25% below 1990 levels; and (iii) by 2050, reduce emissions to 50% below 1990 levels, or 70% below Washington's forecasted emissions in 2050. Oregon's goals seek to (i) by 2010, cease the growth of Oregon greenhouse gas emissions; (ii) by 2020, reduce greenhouse gas levels to 10% below 1990 levels; and (iii) by 2050, reduce greenhouse gas levels to at least 75% below 1990 levels. Each state's legislation also calls for state government-developed policy recommendations in the future to assist in the monitoring and achievement of these goals. The impact of the enacted legislation on PacifiCorp cannot be determined at this time.

PacifiCorp continues to add renewable electric capacity to its generation portfolio. In addition, PacifiCorp has engaged in voluntary programs designed to either reduce or avoid greenhouse gas emissions, including the EPA's sulfur hexafluoride reduction program and refrigerator recycling programs. PacifiCorp is a member of the California Climate Action Registry and The Climate Registry, under which it reports and certifies its greenhouse gas emissions.

The impact of any pending judicial proceedings and any pending or enacted federal and state climate change legislation and regulation cannot be determined at this time; however, adoption of stringent limits on greenhouse gas emissions could significantly impact PacifiCorp's current and future fossil-fueled facilities, and, therefore, its financial results.

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IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

Water Quality Standards

The Clean Water Act establishes the framework for maintaining and improving water quality in the United States through a program that regulates, among other things, discharges to and withdrawals from waterways. The Clean Water Act requires that cooling water intake structures reflect the "best technology available for minimizing adverse environmental impact" to aquatic organisms. In July 2004, the EPA established significant new national technology-based performance standards for existing electric generating facilities that take in more than 50 million gallons of water a day. These rules are aimed at minimizing the adverse environmental impacts of cooling water intake structures by reducing the number of aquatic organisms lost as a result of water withdrawals. In response to a legal challenge to the rule, in January 2007, the Second Circuit Court of Appeals remanded almost all aspects of the rule to the EPA, leaving companies with cooling water intake structures uncertain regarding compliance with these requirements. Petitions for certiorari are pending before the United States Supreme Court regarding the Second Circuit's decision. Compliance and the potential costs of compliance therefore cannot be ascertained until such time as further action is taken by the EPA. Currently, PacifiCorp's Dave Johnston plant exceeds the 50 million gallons of water per day in-take threshold. In the event that PacifiCorp's existing intake structures require modification or alternative technology is required by new rules, expenditures to comply with these requirements could be significant.

Integrated Resource Plans

As required by certain state regulations, PacifiCorp uses an Integrated Resource Plan ("IRP") to develop a long-term view of prudent future actions required to help ensure that PacifiCorp continues to provide reliable and cost-effective electric service to its customers. The IRP process identifies the amount and timing of PacifiCorp's expected future resource needs and an associated optimal future resource mix that accounts for planning uncertainty, risks, reliability impacts and other factors. The IRP is a coordinated effort with stakeholders in each of the six states where PacifiCorp operates. When the IRP is filed, each state commission with IRP adequacy rules judges whether the IRP reasonably meets its standards and guidelines. PacifiCorp requests "acknowledgement" of its IRP filing from the UPSC, the OPUC, the IPUC and the WUTC pursuant to those states' IRP adequacy rules. The IRP can be used as evidence by parties in rate-making or other regulatory proceedings. PacifiCorp files its IRP on a biennial basis.

In May 2007, PacifiCorp released its 2007 IRP. The 2007 IRP identified a need for approximately 3,171 MW of additional resources by summer 2016 to satisfy the difference between projected retail load obligations and available resources. PacifiCorp plans to meet this need through demand response and energy efficiency programs; the construction or purchase of additional generation, including cost-effective renewable energy, combined heat and power, and thermal generation; and wholesale electricity transactions to make up for the remaining difference between retail load obligations and available resources. PacifiCorp is currently seeking acknowledgement of its 2007 IRP from state regulators and expects the acknowledgement process to be complete in 2008.

Requests for Proposal

PacifiCorp has issued a series of separate requests for proposal ("RFP"), each of which focuses on a specific category of resources as provided in the IRP. The IRP and the RFP provide for the identification and staged procurement of resources in future years to achieve load/resource balance. As required by applicable laws and regulations, PacifiCorp files draft RFP with the UPSC, the OPUC and the WUTC prior to issuance to the market.

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IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

In February 2007, PacifiCorp filed a modified 2012 RFP in Utah for up to 1,700 MW of additional resources to become available beginning in 2012 through 2014. The RFP was approved by the UPSC and issued to the market in April 2007. In June 2007, proposals from qualifying bidders were received by commission-directed independent evaluators. These bids included various structures, ranging from purchase or lease of coal, natural gas, and geothermal power plants to power purchase agreements. PacifiCorp initiated negotiations with short-listed bidders in January 2008.

In January 2008, PacifiCorp issued to the market a 2008 renewable RFP for less than 100 MW, or greater than 100 MW for power purchase agreements with a term of less than five years, to become available prior to December 2009.

In February 2008, PacifiCorp filed an all source 2008 RFP with the UPSC, the OPUC and the WUTC for base load, intermediate or third quarter summer peaking products delivered into PacifiCorp's system. The all source 2008 RFP seeks up to 2,000 MW of resources to become available beginning in 2012 through 2016.

In addition to new generation resources, substantial transmission investments are expected to be required to deliver energy to PacifiCorp's growing customer base and to enhance system reliability. The actual investment requirement will depend on the location and other characteristics of the new generation resources.

ITEM 13.

Officer & Director Changes

On March 12, 2007, PacifiCorp's Senior Vice President, Stanley K. Watters, resigned as a director and officer, effective March 16, 2007.

On May 31, 2007, PacifiCorp's Senior Vice President and General Counsel, Mark C. Moench, was elected to the additional office of PacifiCorp Secretary.

On July 25, 2007, Nolan E. Karras resigned as a director of PacifiCorp, effective immediately.

On August 30, 2007, William J. Fehrman resigned as President of PacifiCorp Energy, a division of PacifiCorp, and as a director of PacifiCorp and A. Robert Lasich was elected President of PacifiCorp Energy. Mr. Lasich was serving as Vice President and General Counsel of PacifiCorp Energy and continues to serve as a director of PacifiCorp.

On August 30, 2007, Natalie L. Hocken, Vice President and General Counsel of Pacific Power, and David J. Mendez, Senior Vice President and Chief Financial Officer, were elected directors of PacifiCorp.

On February 8, 2008, PacifiCorp's Senior Vice President and Chief Financial Officer, David J. Mendez, resigned as a director and officer, effective February 29, 2008.

On February 19, 2008, Douglas K. Stuver was appointed Senior Vice President and Chief Financial Officer, effective March 1, 2008. Mr. Stuver was serving as Managing Director and Division Controller of PacifiCorp Energy.

ITEM 14.

None.

INDEPENDENT AUDITORS' REPORT

PacifiCorp
Portland, Oregon

We have audited the balance sheet — regulatory basis of PacifiCorp (the "Company") as of December 31, 2007, and the related statements of income — regulatory basis; retained earnings — regulatory basis; cash flows — regulatory basis, and accumulated comprehensive income, comprehensive income, and hedging activities — regulatory basis for the year ended December 31, 2007, included on pages 110 through 123 of the accompanying Federal Energy Regulatory Commission Form 1. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

As discussed in Note 2, these financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America.

In our opinion, such regulatory-basis financial statements present fairly, in all material respects, the assets, liabilities, and proprietary capital of PacifiCorp as of December 31, 2007, and the results of its operations and its cash flows for the year ended December 31, 2007, in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

This report is intended solely for the information and use of the board of directors and management of PacifiCorp and for filing with the Federal Energy Regulatory Commission and is not intended to be and should not be used by anyone other than these specified parties.

Deloitte + Touche LLP

February 27, 2008

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COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)					
Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)	
1	UTILITY PLANT				
2	Utility Plant (101-106, 114)	200-201	16,637,482,510	15,526,911,439	
3	Construction Work in Progress (107)	200-201	941,818,776	734,457,063	
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		17,579,301,286	16,261,368,502	
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	6,691,765,903	6,408,699,464	
6	Net Utility Plant (Enter Total of line 4 less 5)		10,887,535,383	9,852,669,038	
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)		10,887,535,383	9,852,669,038	
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)		9,436,375	8,945,604	
19	(Less) Accum. Prov. for Depr. and Amort. (122)		1,396,066	1,231,400	
20	Investments in Associated Companies (123)		7,637,258	7,695,513	
21	Investment in Subsidiary Companies (123.1)	224-225	149,005,037	113,111,986	
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)		87,106,834	93,958,194	
25	Sinking Funds (125)		0	0	
26	Depreciation Fund (126)		0	0	
27	Amortization Fund - Federal (127)		0	0	
28	Other Special Funds (128)		9,530,018	7,847,422	
29	Special Funds (Non Major Only) (129)		0	0	
30	Long-Term Portion of Derivative Assets (175)		215,055,123	234,925,374	
31	Long-Term Portion of Derivative Assets - Hedges (176)		0	0	
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		476,374,579	465,252,693	
33	CURRENT AND ACCRUED ASSETS				
34	Cash and Working Funds (Non-major Only) (130)		0	0	
35	Cash (131)		10,512,273	9,559,447	
36	Special Deposits (132-134)		6,256,766	13,969,784	
37	Working Fund (135)		2,670	2,920	
38	Temporary Cash Investments (136)		182,317,755	14,544,663	
39	Notes Receivable (141)		616,766	893,754	
40	Customer Accounts Receivable (142)		373,257,825	324,627,813	
41	Other Accounts Receivable (143)		15,687,039	22,216,920	
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		6,551,765	11,879,646	
43	Notes Receivable from Associated Companies (145)		25,975,115	22,866,308	
44	Accounts Receivable from Assoc. Companies (146)		12,144,713	9,933,523	
45	Fuel Stock (151)	227	98,334,182	82,230,862	
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	150,050,022	129,731,866	
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 PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 110 Line No.: 57 Column:

At December 31, 2007, account 165 Prepayments included \$22.2 million in income taxes receivable due from PPW Holdings LLC, PacifiCorp's direct parent company.

Schedule Page: 110 Line No.: 57 Column:

At December 31, 2006, account 165 Prepayments included \$43.5 million in income taxes receivable due from PPW Holdings LLC, PacifiCorp's direct parent company.

Schedule Page: 110 Line No.: 82 Column:

Deferred tax assets of \$268 million related to accrued removal costs were netted against deferred tax liabilities on property, plant and equipment in account 282 at December 31, 2007. At December 31, 2006, deferred tax assets of \$265 million related to accrued removal costs were included in account 190.

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(Next Page is 112)

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (mo, da, yr) 04/03/2008	Year/Period of Report end of 2007/Q4
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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)		13,034,927	13,982,472
48	Miscellaneous Current and Accrued Liabilities (242)		76,018,366	84,647,611
49	Obligations Under Capital Leases-Current (243)		1,428,748	1,233,704
50	Derivative Instrument Liabilities (244)		613,992,765	612,857,273
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		496,923,540	504,511,387
52	Derivative Instrument Liabilities - Hedges (245)		0	1,186,351
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		798,053,867	1,116,502,553
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		17,485,789	10,343,762
57	Accumulated Deferred Investment Tax Credits (255)	266-267	53,767,820	61,687,940
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	59,527,962	61,791,513
60	Other Regulatory Liabilities (254)	278	71,343,435	109,982,910
61	Unamortized Gain on Reacquired Debt (257)		0	56,166
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	300,173
63	Accum. Deferred Income Taxes-Other Property (282)		1,832,890,057	2,005,573,266
64	Accum. Deferred Income Taxes-Other (283)		294,069,371	427,515,994
65	Total Deferred Credits (lines 56 through 64)		2,329,084,434	2,677,251,724
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		14,304,937,630	13,684,018,151

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 112 Line No.: 63 Column:

Deferred tax assets of \$268 million related to accrued removal costs were netted against deferred tax liabilities on property, plant and equipment in account 282 at December 31, 2007. At December 31, 2006, deferred tax assets of \$265 million related to accrued removal costs were included in account 190.

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(Next Page is 114)

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008		Year/Period of Report End of 2007/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 column in a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.							
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.							
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	4,243,625,971	3,747,281,207			
3	Operating Expenses						
4	Operation Expenses (401)	320-323	2,407,885,415	2,105,021,264			
5	Maintenance Expenses (402)	320-323	378,009,826	352,406,626			
6	Depreciation Expense (403)	336-337	418,496,844	390,945,206			
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337					
8	Amort. & Depl. of Utility Plant (404-405)	336-337	45,276,103	47,633,759			
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	5,479,353	5,479,353			
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		2,452,562	1,674,863			
11	Amort. of Conversion Expenses (407)						
12	Regulatory Debits (407.3)		10,429,071	7,696,523			
13	(Less) Regulatory Credits (407.4)						
14	Taxes Other Than Income Taxes (408.1)	262-263	101,472,747	101,034,471			
15	Income Taxes - Federal (409.1)	262-263	125,610,768	106,778,946			
16	- Other (409.1)	262-263	15,623,546	9,090,310			
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	425,065,057	813,769,788			
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	366,448,712	753,579,201			
19	Investment Tax Credit Adj. - Net (411.4)	266	-5,854,860	-5,854,860			
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)		14,663,498	15,619,250			
23	Losses from Disposition of Allowances (411.9)						
24	Accretion Expense (411.10)						
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		3,548,834,222	3,166,477,798			
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		694,791,749	580,803,409			

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008		Year/Period of Report End of 2007/Q4	
STATEMENT OF INCOME FOR THE YEAR (continued)							
Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL		Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)	
			Current Year (c)	Previous Year (d)			
27	Net Utility Operating Income (Carried forward from page 114)		694,791,749	580,803,409			
28	Other Income and Deductions						
29	Other Income						
30	Nonutility Operating Income						
31	Revenues From Merchandising, Jobbing and Contract Work (415)		2,760,357	3,443,913			
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		2,946,861	3,554,683			
33	Revenues From Nonutility Operations (417)		239,021	156,069			
34	(Less) Expenses of Nonutility Operations (417.1)		25,945	23,117			
35	Nonoperating Rental Income (418)		63,654	60,059			
36	Equity in Earnings of Subsidiary Companies (418.1)	119	1,716,150	-1,831,832			
37	Interest and Dividend Income (419)		13,913,812	7,426,781			
38	Allowance for Other Funds Used During Construction (419.1)		40,906,060	23,612,825			
39	Miscellaneous Nonoperating Income (421)		164,005,754	480,231,577			
40	Gain on Disposition of Property (421.1)		890,266	162,550			
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		221,522,268	509,684,142			
42	Other Income Deductions						
43	Loss on Disposition of Property (421.2)		4,210,041	342,567			
44	Miscellaneous Amortization (425)	340	1,118,623	1,099,117			
45	Donations (426.1)	340	2,863,061	2,144,714			
46	Life Insurance (426.2)		-4,961,276	-7,657,632			
47	Penalties (426.3)		4,184,046	10,058,546			
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,147,711	1,163,251			
49	Other Deductions (426.5)		161,982,725	530,547,357			
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		170,544,931	537,697,920			
51	Taxes Applicable to Other Income and Deductions						
52	Taxes Other Than Income Taxes (408.2)	262-263	223,659	497,588			
53	Income Taxes-Federal (409.2)	262-263	18,941,072	24,842,659			
54	Income Taxes-Other (409.2)	262-263	2,573,778	3,371,372			
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	58,876,813	95,532,620			
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	59,117,957	134,566,999			
57	Investment Tax Credit Adj.-Net (411.5)						
58	(Less) Investment Tax Credits (420)		2,065,260	2,065,260			
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		19,432,105	-12,388,020			
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		31,545,232	-15,625,758			
61	Interest Charges						
62	Interest on Long-Term Debt (427)		278,731,910	245,313,780			
63	Amort. of Debt Disc. and Expense (428)		3,012,770	3,779,288			
64	Amortization of Loss on Reacquired Debt (428.1)		4,651,715	4,847,826			
65	(Less) Amort. of Premium on Debt-Credit (429)		2,718	2,718			
66	(Less) Amortization of Gain on Reacquired Debt-Credit (429.1)		56,166	84,249			
67	Interest on Debt to Assoc. Companies (430)	340		25,955			
68	Other Interest Expense (431)	340	29,764,583	26,043,696			
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		28,653,980	22,680,215			
70	Net Interest Charges (Total of lines 62 thru 69)		287,448,114	257,243,363			
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		438,888,867	307,934,288			
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)		438,888,867	307,934,288			

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 114 Line No.: 6 Column: c

Vehicle depreciation is charged to functional accounts. The following table summarizes the vehicle depreciation expense that was charged to the functional accounts.

	Twelve Months Ending December 31,	
	2007	2006
Vehicle Depreciation	\$ 12,494,116	\$ 12,268,419

Schedule Page: 114 Line No.: 7 Column: c

PacifiCorp records the depreciation expense of asset retirement obligations as either a regulatory asset or liability.

Schedule Page: 114 Line No.: 14 Column: c

Payroll taxes are charged to functional accounts, which is consistent with where labor is charged. The following table summarizes the payroll tax expense that was charged to the functional accounts.

	Twelve Months Ending December 31,	
	2007	2006
Payroll Tax Expense	\$ 35,600,794	\$ 36,613,788

Schedule Page: 114 Line No.: 24 Column: c

PacifiCorp records the accretion expense of asset retirement obligations as either a regulatory asset or liability.

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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STATEMENT OF RETAINED EARNINGS

- Do not report Lines 49-53 on the quarterly version.
- Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
- 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)
- State the purpose and amount of each reservation or appropriation of retained earnings.
- 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.
- Show dividends for each class and series of capital stock.
- Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
- 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.
- 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		779,888,925	488,980,264
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	FIN 48 Adoption	236	13,325,103	
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		13,325,103	
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		437,172,717	309,766,120
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24	Preferred Stock - Various series and rates	238	-2,083,790	(2,083,790)
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-2,083,790	(2,083,790)
30	Dividends Declared-Common Stock (Account 438)			
31	Common stock	238		(16,773,669)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)			(16,773,669)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,228,302,955	779,888,925
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
PacifiCorp			
FOOTNOTE DATA			

Schedule Page: 118 Line No.: 4 Column: c

For a discussion regarding PacifiCorp's adoption of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109" ("FIN 48") refer to Note 2 of Notes to Financial Statements included in this Form 1.

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(Next Page is 120)

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	438,888,867	307,934,288
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	431,935,488	403,735,798
5	Amortization:	64,755,712	63,583,615
6			
7	Unrealized (Gains)/Losses on Derivative Contracts	-1,661,541	51,066,157
8	Deferred Income Taxes (Net)	45,331,714	21,156,209
9	Investment Tax Credit Adjustment (Net)	-7,920,120	-7,920,120
10	Net (Increase) Decrease in Receivables	-70,906,726	-82,840,925
11	Net (Increase) Decrease in Inventory	-36,421,476	-37,371,890
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	45,187,940	116,660,014
14	Net (Increase) Decrease in Other Regulatory Assets	-18,006,439	14,522,865
15	Net Increase (Decrease) in Other Regulatory Liabilities	-27,468,274	-3,472,833
16	(Less) Allowance for Other Funds Used During Construction	40,906,060	23,612,825
17	(Less) Undistributed Earnings from Subsidiary Companies	1,716,150	-1,831,832
18	Amounts Due to/From Affiliates, Net	20,506,275	-52,647,096
19	Other Operating Activities:	-14,775,749	-36,872,203
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	826,823,461	735,752,886
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-1,525,508,915	-1,339,383,764
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-40,906,060	-23,612,825
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,484,602,855	-1,315,770,939
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	2,685,689	309,662
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-22,349,232	-38,211,124
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 PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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STATEMENT OF CASH FLOWS

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

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

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

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
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 Investing Activities:	13,017,394	-7,854,645
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,491,249,004	-1,361,527,046
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	1,193,405,452	348,333,528
62	Preferred Stock		
63	Common Stock		109,722,222
64	Equity Contribution	200,000,000	214,950,000
65			
66	Net Increase in Short-Term Debt (c)		182,634,965
67	Other (provide details in footnote):	3,502,924	1,816,877
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,396,908,376	857,457,592
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-125,667,000	-310,552,000
74	Preferred Stock	-37,500,000	-7,500,000
75	Common Stock		
76	Intercompany Borrowings		-1,595,907
77	Repayment of Capital Lease Obligations	-1,254,709	-547,822
78	Net Decrease in Short-Term Debt (c)	-397,251,666	
79			
80	Dividends on Preferred Stock	-2,083,790	-2,083,790
81	Dividends on Common Stock		-16,773,669
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	833,151,211	518,404,404
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	168,725,668	-107,369,756
87			
88	Cash and Cash Equivalents at Beginning of Period	24,107,030	131,476,786
89			
90	Cash and Cash Equivalents at End of period	192,832,698	24,107,030

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

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

	YTD 12/31/2007	YTD 12/31/2006	FERC Account
Amortization of Software Development & Other Intangibles	\$ 45,276,103	\$ 47,633,759	404
Amortization of Licensing/Hydro	1,118,623	1,099,117	425
Amortization of Electric Plant Acquisition Adjustment	5,479,353	5,479,353	406
Amortization of Regulatory Assets	12,881,633	9,371,386	407/407.3
	\$ 64,755,712	\$ 63,583,615	

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

	YTD 12/31/2007	YTD 12/31/2006	FERC Account
Coal Depreciation & Depletion included in Cost of Fuel	\$ 15,163,499	\$ 13,481,495	151
PMI Equity Earnings eliminated in Cost of Fuel	(6,808,915)	(11,269,409)	501
(Gain)/Loss on Sale of Property	893,597	(127,201)	254 / 411.6 / 411.7
Deferred Credits - Deferred Compensation	(6,385,866)	(1,232,359)	253.4
Accumulated Provision for Pension & Benefits	(19,781,800)	(33,547,909)	228
Write-Off of Assets Under Construction	10,602,121	1,598,165	107
IRC Section 199 Tax Deduction	-	(1,275,241)	211
Accum Provision for Mining/Environ/Decom	(5,632,346)	(7,075,262)	228 / 253
Other	(2,826,039)	2,575,518	Various
	\$ (14,775,749)	\$ (36,872,203)	

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

	YTD 12/31/2007	YTD 12/31/2006	FERC Account
Other Investments/Special Funds	\$ 7,670,035	\$ (256,759)	124 / 128
Temporary Facilities	(78,766)	97,548	185
Restricted Cash	5,426,125	(2,521,393)	128 / 134
Business Acquisition of Steam Reserve Corporation	-	(5,174,041)	101
	\$ 13,017,394	\$ (7,854,645)	

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

	YTD 12/31/2007	YTD 12/31/2006	FERC Account
Contribution Received from MEHC from the Acquisition of IGC	\$ -	\$ 2,330,669	211
Tax Benefit of Stock Options Exercised	3,502,924	-	211
Other Equity Adjustments	-	(513,792)	211
Net Additional Paid-In Capital	\$ 3,502,924	\$ 1,816,877	

Schedule Page: 120 Line No.: 74 Column: b

Represents redemption of preferred stock subject to mandatory redemption, which is classified as Long-term debt on the Balance Sheet. This represents all remaining outstanding shares of PacifiCorp's \$7.48 No Par Serial Preferred Stock series.

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report 04/03/2008	Year/Period of Report End of 2007/Q4
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NOTES TO FINANCIAL STATEMENTS

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

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
PacifiCorp			
NOTES TO FINANCIAL STATEMENTS (Continued)			

PACIFICORP
NOTES TO THE FINANCIAL STATEMENTS

(1) Organization and Operations

PacifiCorp (which includes PacifiCorp and its subsidiaries) is a United States regulated electricity company serving 1.7 million retail customers, including residential, commercial, industrial and other customers in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp owns, or has interests in, a number of thermal, hydroelectric and wind-powered generating plants, as well as electric transmission and distribution assets. PacifiCorp also buys and sells electricity on the wholesale market with public and private utilities, energy marketing companies and incorporated municipalities. The regulatory commission in each state approves rates for retail electric sales within that state. PacifiCorp's consolidated subsidiaries support its electric utility operations by providing coal-mining facilities and services.

On March 21, 2006, a wholly owned subsidiary of MidAmerican Energy Holdings Company ("MEHC") acquired 100% of the common stock of PacifiCorp from a wholly owned subsidiary of Scottish Power plc ("ScottishPower"). As a result of this acquisition, MEHC controls substantially all of PacifiCorp's voting securities, which include both common and preferred stock. MEHC, a holding company based in Des Moines, Iowa, owning subsidiaries that are principally engaged in energy businesses, is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

(2) Summary of Significant Accounting Policies

Basis of Presentation

These financial statements are prepared in accordance with the requirements of the Federal Energy Regulatory Commission ("the FERC") as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America ("GAAP"). These notes include disclosures required by GAAP adjusted to the FERC basis of presentation, and include specific information requested by the FERC.

The following are the significant differences between the FERC reporting standards and GAAP:

Investments in Subsidiaries

PacifiCorp accounts for certain investments in subsidiaries using the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiaries as required by GAAP. GAAP requires that majority-owned subsidiaries and variable-interest entities for which a company is the primary beneficiary be consolidated in accordance with Statement of Financial Accounting Standards ("SFAS") No. 94, *Consolidation of All Majority-Owned Subsidiaries* and revised Financial Accounting Standards Board (the "FASB") Interpretation No. 46, *Consolidation of Variable-Interest Entities, an interpretation of Accounting Research Bulletin No. 51*. In general, the accounting for investments in these certain subsidiaries using the equity method rather than the consolidation method in accordance with GAAP has no effect on net income or retained earnings.

Accumulated Removal Costs

The accumulated removal costs for PacifiCorp's regulated property, plant and equipment that do not meet the definition of an asset retirement obligation under SFAS No. 143, *Accounting for Asset Retirement Obligations*, are classified as a regulatory liability under GAAP and as accumulated provision for depreciation under the FERC reporting standards.

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

Accumulated Deferred Income Taxes

Accumulated deferred income taxes are classified as current and non-current for GAAP, by presenting net current assets and liabilities separate from net non-current assets and liabilities on the balance sheet in accordance with SFAS No. 109, *Accounting for Income Taxes*. All such amounts are classified as gross non-current assets and gross non-current liabilities for the FERC reporting standards.

Accumulated deferred income taxes are determined for GAAP as the difference between the tax basis of an asset or liability as determined in accordance with the recognition and measurement provisions of FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109* ("FIN 48"), and its reported amount in the financial statements. All such amounts are determined for FERC as the difference between the tax basis of an asset or liability as reflected or expected to be reflected in a tax return and its reported amount in the financial statements.

Interest and penalties on income taxes for GAAP are classified as income tax expense as permissible by FIN 48. All such amounts are classified as interest income, interest expense and penalties for FERC on the Statement of Income.

Unrealized Gains and Losses on Derivative Instruments

The FERC accounting standards require that unrealized gains and losses on derivative instruments that are not probable of recovery in rates be classified gross on the income statement in accordance with FERC Order 627, *Accounting and Reporting of Financial Instruments, Comprehensive Income, Derivatives and Hedging Activities*. Unrealized gains and losses on energy contracts accounted for as derivatives are presented in the Statement of Income as Miscellaneous nonoperating income for unrealized gains and as Other deductions for unrealized losses. For GAAP, unrealized gains and losses on energy derivative contracts not held for trading purposes are presented on the Statements of Income as revenues for sales contracts and as energy costs and operating expense for purchase contracts.

Reclassifications

Certain other reclassifications of balance sheet, income statement and cash flow amounts have been made in order to conform to the FERC basis of presentation. These reclassifications had no effect on net income.

Change in Fiscal Year

On May 10, 2006, the PacifiCorp Board of Directors elected to change PacifiCorp's fiscal year-end from March 31 to December 31. See PacifiCorp's Securities and Exchange Commission (the "SEC") Transition Report on Form 10-K for the nine-month period ended December 31, 2006 for consolidated financial statements and complete footnotes prepared in accordance with GAAP.

Use of Estimates in Preparation of Financial Statements

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. These estimates include, but are not limited to: unbilled receivables; valuation of energy contracts; the effects of regulation; the accounting for contingencies, including environmental, regulatory and income tax matters; and certain assumptions made in accounting for pension and other postretirement benefits. Actual results may differ from the estimates used in preparing the financial statements.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
PacifiCorp	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 04/03/2008	2007/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

Cash Equivalents

Cash equivalents consist of funds invested in money market funds and in other investments with a maturity of three months or less when purchased.

(Millions of dollars)	December 31, 2007	December 31, 2006
Cash (131)	\$ 11	\$ 10
Working funds (135)	-	-
Temporary cash investments (136)	<u>182</u>	<u>14</u>
Total cash and cash equivalents	<u>\$ 193</u>	<u>\$ 24</u>

Accounting for the Effects of Certain Types of Regulation

PacifiCorp prepares its financial statements in accordance with the provisions of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation* ("SFAS No. 71"), which differs in certain respects from the application of GAAP by non-regulated businesses. In general, SFAS No. 71 recognizes that accounting for rate-regulated enterprises should reflect the economic effects of regulation. As a result, a regulated entity is required to defer the recognition of costs or income if it is probable that, through the rate-making process, there will be a corresponding increase or decrease in future rates. Accordingly, PacifiCorp has deferred certain costs and income that will be recognized in earnings over various future periods.

Management continually evaluates the applicability of SFAS No. 71 and assesses whether its regulatory assets are probable of future recovery by considering factors such as a change in the regulator's approach to setting rates from cost-based rate-making to another form of regulation; other regulatory actions; or the impact of competition, which could limit PacifiCorp's ability to recover its costs. Based upon this continual assessment, management believes the application of SFAS No. 71 continues to be appropriate and its existing regulatory assets are probable of recovery. The assessment reflects the current political and regulatory climate at both the state and federal levels and is subject to change in the future. If it becomes probable that these costs will not be recovered, the assets and liabilities would be written off and recognized in the statement of income.

Allowance for Doubtful Accounts

The allowance for doubtful accounts is based on PacifiCorp's assessment of the collectibility of payments from its customers. This assessment requires judgment regarding the ability of customers to pay the amounts owed to PacifiCorp and the outcome of pending disputes and arbitrations. At December 31, 2007 and 2006, the allowance for doubtful accounts totaled \$7 million and \$12 million, respectively.

Derivatives

PacifiCorp employs a number of different derivative instruments in connection with its electric, natural gas and foreign currency exchange rate activities, including forward purchases and sales, swaps and options. Derivative instruments are recorded in the Comparative Balance Sheet at fair value as either assets or liabilities unless they are designated and qualify for the normal purchases and normal sales exemption afforded by GAAP. Contracts that qualify as normal purchases or normal sales are not marked to market. Derivative contracts for commodities used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases and normal sales pursuant to the exemption. Recognition of these contracts in revenues or Operation expenses in the Statement of Income occurs when the contracts settle.

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PacifiCorp			
NOTES TO FINANCIAL STATEMENTS (Continued)			

For contracts designated in hedge relationships ("hedge contract"), PacifiCorp maintains formal documentation of the hedge. In addition, at inception and on a quarterly basis, PacifiCorp formally assesses whether hedge contracts are highly effective in offsetting changes in cash flows of the hedged items. PacifiCorp documents hedging activity by transaction type and risk management strategy.

Changes in the fair value of a derivative designated and qualifying as a cash flow hedge, to the extent effective, are included in the Statements of Accumulated Comprehensive Income, Comprehensive Income and Hedging Activities, as Accumulated other comprehensive income, net of tax, until the hedged item is recognized in earnings. PacifiCorp discontinues hedge accounting prospectively when it has determined that a derivative no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, future changes in the value of the derivative are charged to earnings. Gains and losses related to discontinued hedges that were previously recorded in Accumulated other comprehensive income will remain in Accumulated other comprehensive income until the hedged item is realized, unless it is probable that the hedged forecasted transaction will not occur, at which time associated deferred amounts in Accumulated other comprehensive income are immediately recognized in current earnings.

Certain derivative contracts utilized by PacifiCorp are recoverable through rates. Accordingly, unrealized changes in fair value of these contracts are deferred as net regulatory assets or liabilities pursuant to SFAS No. 71.

When available, quoted market prices or prices obtained through external sources are used to measure a contract's fair value. For contracts without available quoted market prices, fair value is determined based on internally developed modeled prices. The fair value of these instruments is a function of underlying forward commodity prices, related volatility, counterparty creditworthiness and duration of the contracts.

Inventories

Inventories consist mainly of materials and supplies, coal stocks, natural gas and fuel oil, which are valued at the lower of average cost or market.

Property, Plant and Equipment, Net

General

Property, plant and equipment are recorded at historical cost. PacifiCorp capitalizes all construction-related material, direct labor costs and contract services, as well as indirect construction costs, which include allowance for funds used during construction. The cost of major additions and betterments are capitalized, while costs for replacements, maintenance and repairs that do not improve or extend the lives of the respective assets are charged to operating expense.

Generally when PacifiCorp retires its regulated property, plant and equipment, it charges the original cost and any cost of removal and salvage to accumulated provision for depreciation. Generally when PacifiCorp sells its regulated property, plant and equipment, the cost is removed from the property accounts and the related accumulated provision for depreciation and amortization accounts are reduced and any residual gain or loss is amortized through future depreciation expense.

PacifiCorp records an allowance for funds used during construction, which represents the estimated cost of debt and equity costs of capital funds necessary to finance construction of plants. Allowance for funds used during construction is capitalized as a component of property, plant and equipment, with offsetting credits to the Statement of Income. After construction is completed, PacifiCorp is permitted to earn a return on these costs by their inclusion in rate base, as well as recover these costs through depreciation expense over the useful life of the related assets.

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NOTES TO FINANCIAL STATEMENTS (Continued)			

The weighted-average aggregate rates used for the allowance for funds used during construction were 8.3% for the year ended December 31, 2007 and 7.7% for the year ended December 31, 2006.

Intangible plant consists primarily of computer software costs that are originally recorded at cost. Accumulated amortization on intangible plant was \$378 million at December 31, 2007 and \$358 million at December 31, 2006. Amortization expense on intangible plant was \$44 million during the year ended December 31, 2007 and \$46 million during the year ended December 31, 2006. The estimated aggregate amortization on intangible plant for the years ending from December 31, 2008 through 2012 is \$39 million in 2008, \$31 million in 2009, \$27 million in 2010, \$26 million in 2011 and \$24 million in 2012. Unamortized computer software costs were \$149 million at December 31, 2007 and \$177 million at December 31, 2006.

PacifiCorp has unallocated acquisition adjustments that represent the excess of costs of the acquired interests in property, plant and equipment purchased from other regulated utilities over their net book value in those assets. These unallocated acquisition adjustments had an original cost of \$157 million at December 31, 2007 and 2006, and accumulated provision for depreciation of \$85 million and \$80 million at December 31, 2007 and 2006, respectively.

Asset Retirement Obligations

PacifiCorp recognizes legal asset retirement obligations, mainly related to the final reclamation of leased coal-mining property. The fair value of a liability for a legal asset retirement obligation is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the liability is adjusted for any revisions to the expected value of the retirement obligation (with corresponding adjustments to property, plant and equipment) and for accretion of the liability due to the passage of time. The difference between the asset retirement obligations liability, the corresponding asset retirement obligations asset included in property, plant and equipment and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability. Estimated removal costs that PacifiCorp recovers through approved depreciation rates but that do not meet the requirements of legal asset retirement obligations are accumulated in accumulated provision for depreciation in the Comparative Balance Sheet.

Depreciation and Amortization

Depreciation and amortization are computed by the straight-line group method either over the life prescribed by PacifiCorp's various regulatory jurisdictions for regulated assets or over the assets' estimated useful lives. The composite depreciation rate of average depreciable assets on utility property, plant and equipment was 3% for the years ended December 31, 2007 and 2006.

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

The average depreciable lives of property, plant and equipment currently in use by category are as follows:

Computer software costs included in intangible plant are initially assigned a depreciable life of 5 to 10 years.

Generation

Steam plant	20 – 43 years
Hydroelectric plant	14 – 85 years
Wind plant	25 years
Other plant	15 – 35 years
Transmission	20 – 70 years
Distribution	44 – 50 years
Intangible plant	5 – 50 years
Other	5 – 30 years

In August 2007, PacifiCorp filed applications with the regulatory commissions in Utah, Oregon, Wyoming, Washington and Idaho to change the rates of depreciation. Agreements have been reached in each of these states and are in various stages of approval. Based on the new depreciation study, PacifiCorp expects the depreciable lives of its property, plant and equipment generally to be extended beyond the lives assumed as of December 31, 2007. The most significant change is expected to result in increasing the range of depreciable lives for steam plant from 20 – 43 years to 20 – 57 years. When approved by the state commissions, the agreements will make the new depreciation rates effective January 1, 2008.

Revenue Recognition

Revenue from customers is recognized as electricity is delivered and includes amounts for services rendered. Revenue recognized includes unbilled, as well as billed, amounts. Rates charged are subject to federal and state regulation.

Electricity sales to retail customers are determined based on meter readings taken throughout the month. PacifiCorp accrues an estimate of unbilled revenues, which are earned but not yet billed, net of estimated line losses, each month for electric service provided after the meter reading date to the end of the month. The process of calculating the unbilled revenue estimate consists of three components: quantifying PacifiCorp's total electricity delivered during the month, assigning unbilled revenues to customer type and valuing the unbilled energy. Factors involved in the estimation of consumption and line losses relate to weather conditions, amount of natural light, historical trends, economic impacts and customer type. Valuation of unbilled energy is based on estimating the average price for the month for each customer type.

PacifiCorp records sales, franchise and excise taxes, which are collected directly from PacifiCorp's customers and remitted directly to taxing authorities, on a net basis in the Statement of Income.

Income Taxes

As a result of the sale of PacifiCorp to MEHC on March 21, 2006, Berkshire Hathaway Inc. commenced including PacifiCorp in its United States federal income tax return. PacifiCorp's provision for income taxes has been computed on the basis that it files separate consolidated income tax returns. Prior to the sale, PacifiCorp was included in the consolidated United States federal income tax return for PacifiCorp Holdings Inc. ("PHI").

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
PacifiCorp			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Deferred tax assets and liabilities are based on differences between the financial statements and tax bases of assets and liabilities using the estimated tax rates in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities that are associated with components of Other comprehensive income are charged or credited directly to Other comprehensive income. Changes in deferred income tax assets and liabilities that are associated with income tax benefits related to certain property-related basis differences and other various differences that PacifiCorp is required to pass on to its customers in most state jurisdictions are charged or credited directly to a regulatory asset or regulatory liability. These amounts were recognized as a net regulatory asset of \$423 million at December 31, 2007, and will be included in rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense.

Investment tax credits are generally deferred and amortized over the estimated useful lives of the related properties or as prescribed by various regulatory jurisdictions.

In determining PacifiCorp's tax liabilities, management is required to interpret complex tax laws and regulations. In preparing tax returns, PacifiCorp is subject to continuous examinations by federal, state and local tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. The Internal Revenue Service has closed its examination of PacifiCorp's income tax returns through the 2000 tax year. In addition, open tax years related to a number of state jurisdictions remain subject to examination. Although the ultimate resolution of PacifiCorp's federal and state tax examinations is uncertain, PacifiCorp believes it has made adequate provisions for these tax positions and the aggregate amount of any additional tax liabilities that may result from these examinations, if any, will not have a material adverse effect on PacifiCorp's financial condition, results of operations or cash flows.

Segment Information

PacifiCorp currently has one segment, which includes the regulated retail and wholesale electric utility operations.

New Accounting Pronouncements

FIN 48

In July 2006, the FASB issued FIN 48. PacifiCorp adopted the provisions of FIN 48 on January 1, 2007. Under FIN 48, tax benefits are recognized only for tax positions that are more likely than not to be sustained upon examination by tax authorities. The amount recognized is measured as the largest amount of benefit that is greater than 50% likely to be realized upon ultimate settlement. Unrecognized tax benefits are tax benefits claimed in PacifiCorp's tax returns that do not meet these recognition and measurements standards. In May 2007, the FERC issued guidance under Docket No. AI07-2-000 ("AI07-2"), that clarifies the FERC's view on the financial statement presentation of certain items impacted by FIN 48. PacifiCorp adopted the requirements of AI07-2 as of December 31, 2007. Refer to Note 8 for additional discussion.

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

SFAS No. 141(R)

In December 2007, the FASB issued SFAS No. 141(R), *Business Combinations* ("SFAS No. 141(R)"). SFAS No. 141(R) applies to all transactions or other events in which an entity obtains control of one or more businesses. SFAS No. 141(R) establishes how the acquirer of a business should recognize, measure and disclose in its financial statements the identifiable assets and goodwill acquired, the liabilities assumed and any noncontrolling interest in the acquired business. SFAS No. 141(R) is applied prospectively for all business combinations with an acquisition date on or after the beginning of the first annual reporting period beginning on or after December 15, 2008, with early application prohibited. SFAS No. 141(R) will not have an impact on PacifiCorp's historical financial statements and will be applied to business combinations completed, if any, on or after January 1, 2009.

SFAS No. 160

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements—an amendment of ARB No. 51* ("SFAS No. 160"). SFAS No. 160 establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS No. 160 requires entities to report noncontrolling interests as a separate component of shareholders' equity in the consolidated financial statements. The amount of earnings attributable to the parent and to the noncontrolling interests should be clearly identified and presented on the face of the consolidated statements of operations. Additionally, SFAS No. 160 requires any changes in a parent's ownership interest of its subsidiary, while retaining its control, to be accounted for as equity transactions. SFAS No. 160 is effective for fiscal years beginning on or after December 15, 2008 and interim periods within those fiscal years. PacifiCorp is currently evaluating the impact of adopting SFAS No. 160 on its financial position and results of operations.

SFAS No. 161

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133* ("SFAS No. 161"). SFAS No. 161 revises and enhances the disclosure requirements for derivative instruments and related hedging items as defined under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. The amended disclosures include tabular quantitative disclosures about the fair value of derivative instruments and the related gains and losses on those instruments during the reporting period. Additionally, SFAS No. 161 requires qualitative disclosures about the objectives and strategies for using derivative and hedging instruments and the underlying risk exposures of those items. SFAS No. 161 is effective for fiscal years beginning after November 15, 2008 and interim periods within those fiscal years. PacifiCorp is currently evaluating the impact of adopting SFAS No. 161.

SFAS No. 159

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities—Including an Amendment to SFAS No. 115* ("SFAS No. 159"). SFAS No. 159 permits entities to elect to measure many financial instruments and certain other items at fair value. Upon adoption of SFAS No. 159, an entity may elect the fair value option for eligible items that exist at the adoption date. Subsequent to the initial adoption, the election of the fair value option should only be made at initial recognition of the asset or liability or upon a remeasurement event that gives rise to new-basis accounting. The decision about whether to elect the fair value option is applied on an instrument-by-instrument basis, is irrevocable and is applied only to an entire instrument and not only to specified risks, cash flows or portions of that instrument. SFAS No. 159 does not affect any existing accounting standards that require certain assets and liabilities to be carried at fair value nor does it eliminate disclosure requirements included in other accounting standards. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. PacifiCorp does not anticipate electing the fair value option for any existing eligible items. However, PacifiCorp will continue to evaluate items on a case-by-case basis for consideration under the fair value option.

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SFAS No. 157

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* ("SFAS No. 157"). SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 does not impose fair value measurements on items not already accounted for at fair value; rather, it applies, with certain exceptions, to other accounting pronouncements that either require or permit fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. PacifiCorp is currently evaluating the impact of adopting SFAS No. 157 on its financial position or results of operations.

SFAS No. 158

In September 2006, the FASB issued SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans—an amendment of FASB Statements No. 87, 88, 106, and 132(R)* ("SFAS No. 158"). PacifiCorp adopted the recognition and related disclosure provisions of SFAS No. 158 as of December 31, 2006. SFAS No. 158 also requires that an employer measure plan assets and obligations as of the end of the employer's fiscal year, eliminating the option in SFAS No. 87 and SFAS No. 106 to measure up to three months prior to the financial statement date. The requirement to measure plan assets and benefit obligations as of the date of the employer's fiscal year-end is not required until fiscal years ending after December 15, 2008. As of December 31, 2007, PacifiCorp had not yet adopted the measurement date provisions of the statement. Upon adoption of the measurement date provisions, PacifiCorp will be required to record a transitional adjustment to retained earnings or to a regulatory asset depending on whether the amount is considered probable of being recovered in rates.

(3) Regulatory Matters

Regulatory Assets and Liabilities

PacifiCorp is subject to the jurisdiction of public utility regulatory authorities of the states in which it conducts retail electric operations with respect to prices, services, accounting, issuance of securities and other matters. At present, PacifiCorp is subject to cost-based rate-making for its business. PacifiCorp is a "licensee" and a "public utility" as those terms are used in the Federal Power Act and is therefore subject to regulation by the FERC as to accounting policies and practices, certain prices and other matters. PacifiCorp had regulatory assets not earning a return on investment of \$945 million at December 31, 2007.

Rate Matters

In October 2007, PacifiCorp filed its 2006 tax report under Oregon Senate Bill 408 ("SB 408"), which was enacted in September 2005. SB 408 requires that PacifiCorp and other large regulated, investor-owned utilities that provide electric or natural gas service to Oregon customers file an annual tax report with the Oregon Public Utility Commission (the "OPUC"). PacifiCorp's filing indicates that in 2006, PacifiCorp paid \$33 million more in federal, state and local taxes than was collected in rates from its retail customers. PacifiCorp proposes to amortize \$27 million of the surcharge over a one-year period, which would result in an average price increase of 3%. If the OPUC issues an order providing for recovery in excess of \$27 million and allows the deferral of the excess, the portion not yet recovered will be tracked in a balancing account accruing interest at PacifiCorp's weighted cost of capital. The deferred amount, if any, would be addressed in a subsequent SB 408 filing. The 2006 tax report is currently being challenged during the 180-day procedural schedule that follows the date of the filing, with rates potentially effective June 2008. As part of the review process, PacifiCorp updated its filing for OPUC staff recommendations which increased the initial request by \$2 million for a total of \$35 million. PacifiCorp expects to file its 2007 tax report under SB 408 during the fourth quarter of 2008. PacifiCorp has not recorded any amounts related to either the 2006 tax report or the 2007 expected filing.

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(4) **Short-Term Borrowings**

Short-Term Debt

At December 31, 2007, PacifiCorp did not have any outstanding short-term debt borrowings. At December 31, 2006, PacifiCorp's outstanding short-term borrowings consisted of commercial paper arrangements of \$399 million at an average interest rate of 5.3%.

Revolving Credit Agreements

At December 31, 2007, PacifiCorp had \$1.5 billion available under its unsecured revolving credit facilities. During the year ended December 31, 2007, PacifiCorp entered into an unsecured revolving credit facility with total bank commitments of \$700 million available through October 23, 2012. Under PacifiCorp's existing unsecured revolving credit facility, \$800 million is available through July 6, 2011 and \$760 million is available from July 7, 2011 through July 6, 2012. Each credit facility includes a variable interest rate borrowing option based on the London Interbank Offered Rate plus a margin that is currently 0.195% that varies based on PacifiCorp's credit ratings for its senior unsecured long-term debt securities and supports PacifiCorp's commercial paper program. At December 31, 2007 and 2006, PacifiCorp had no borrowings outstanding under either credit facility.

PacifiCorp's revolving credit and other financing agreements contain customary covenants and default provisions, including a covenant not to exceed a specified debt-to-capitalization ratio of 0.65 to 1.0. At December 31, 2007, PacifiCorp was in compliance with the covenants of its revolving credit and other financing agreements.

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(5) **Long-Term Debt, Preferred Stock Subject to Mandatory Redemption and Capital Lease Obligations**

PacifiCorp's long-term debt, preferred stock subject to mandatory redemption and capital lease obligations were as follows (in millions):

	December 31, 2007		December 31, 2006	
	Amount	Average Interest Rate	Amount	Average Interest Rate
First mortgage bonds:				
4.3% to 9.2%, due through 2012	\$ 1,169	6.6%	\$ 1,295	6.6%
5.0% to 8.8%, due 2013 to 2017	442	5.5	442	5.5
8.1% to 8.5%, due 2018 to 2022	175	8.1	175	8.1
6.7% to 8.2%, due 2023 to 2026	249	7.0	249	7.0
7.7% due 2031	300	7.7	300	7.7
5.3% to 6.3%, due 2034 to 2037	2,050	5.9	850	5.8
Unamortized discount	(5)		(5)	
Pollution-control revenue obligations:				
Variable rates, due 2013 (a) (b)	41	3.8	41	4.0
Variable rates, due 2014 to 2025 (b)	325	3.5	325	3.9
Variable rates, due 2024 (a) (b)	176	3.8	176	4.0
3.4% to 5.7%, due 2014 to 2025 (a)	184	4.5	184	4.5
6.2% due 2030	13	6.2	13	6.2
Unamortized discount	(1)		(1)	
Total long-term debt	\$ 5,118		\$ 4,044	
Other long-term debt:				
Preferred stock subject to mandatory redemption, due 2007	\$ -		\$ 38	
Capital lease obligations:				
10.4% to 14.8%, due through 2036	49	11.3	50	11.7
Total	5,167		4,132	
Less current maturities	(1)		(1)	
Total	\$ 5,166		\$ 4,131	

- (a) Secured by pledged first mortgage bonds generally at the same interest rates, maturity dates and redemption provisions as the pollution-control revenue bond obligations.
- (b) Interest rates fluctuate based on various rates, primarily on certificate of deposit rates, interbank borrowing rates, prime rates or other short-term market rates.

First mortgage bonds of PacifiCorp may be issued in amounts limited by PacifiCorp's property, earnings and other provisions of PacifiCorp's mortgage. Approximately \$16 billion of the eligible assets (based on original cost) of PacifiCorp were subject to the lien of the mortgage at December 31, 2007.

In October 2007, PacifiCorp issued \$600 million of its 6.25% First Mortgage Bonds due October 15, 2037. In March 2007, PacifiCorp issued \$600 million of its 5.75% First Mortgage Bonds due April 1, 2037.

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As of December 31, 2007, \$3.9 billion of first mortgage bonds were redeemable at PacifiCorp's option at redemption prices dependent upon United States Treasury yields. As of December 31, 2007, \$542 million of variable-rate pollution-control revenue bond obligations were redeemable at PacifiCorp's option at par.

As of December 31, 2007, \$71 million of fixed-rate pollution-control revenue bond obligations were redeemable at PacifiCorp's option at par and another \$13 million at 101% of par. The remaining long-term debt was not redeemable at December 31, 2007.

At December 31, 2007, PacifiCorp had \$518 million of standby letters of credit and standby bond purchase agreements available to provide credit enhancement and liquidity support for variable-rate pollution-control revenue bond obligations. These committed bank arrangements were all fully available at December 31, 2007 and expire periodically through May 2012.

In addition, at December 31, 2007, PacifiCorp had approximately \$18 million of standby letters of credit available to provide credit support for certain transactions as requested by third parties. These committed bank arrangements were all fully available at December 31, 2007 and have provisions that automatically extend the annual expiration dates for an additional year unless the issuing bank elects not to renew a letter of credit prior to the expiration date.

PacifiCorp's standby letters of credit and standby bond purchase agreements generally contain similar covenants and default provisions to those contained in PacifiCorp's revolving credit agreement, including a covenant not to exceed a specified debt-to-capitalization ratio of 0.65 to 1.0. PacifiCorp monitors these covenants on a regular basis in order to ensure that events of default will not occur and at December 31, 2007, PacifiCorp was in compliance with these covenants.

PacifiCorp has entered into long-term agreements that expire at various dates through October 2036 for transportation services, real estate and for the use of certain equipment which qualify as capital leases. The transportation services agreements included as capital leases are for the right to use newly constructed pipeline facilities to provide natural gas to two of PacifiCorp's power plants. There were no non-cash capital lease additions to property, plant and equipment during the year ended December 31, 2007. Non-cash capital lease additions to property, plant and equipment were \$13 million during the year ended December 31, 2006. Assets accounted for as capital leases of \$49 million as of December 31, 2007 and 2006 were included in Utility plant in the Comparative Balance Sheet.

In June 2007, PacifiCorp redeemed \$38 million of outstanding preferred stock subject to mandatory redemption, representing all remaining outstanding shares of PacifiCorp's \$7.48 No Par Serial Preferred Stock Series. At December 31, 2006, PacifiCorp had 375,000 No Par Serial Preferred shares outstanding with a \$100 stated value, totaling \$38 million. During the year ended December 31, 2006, PacifiCorp redeemed \$8 million of preferred stock subject to mandatory and optional redemption.

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The annual maturities of long-term debt and capital lease obligations for the years ending December 31 are (in millions):

	Long-term Debt	Capital Lease Obligations	Total
2008	\$ 412	\$ 7	\$ 419
2009	139	7	146
2010	15	7	22
2011	587	7	594
2012	17	7	24
Thereafter	<u>3,954</u>	<u>85</u>	<u>4,039</u>
Total	5,124	120	5,244
Unamortized discount	(6)	-	(6)
Amounts representing interest (a)	-	(71)	(71)
Total	<u>\$ 5,118</u>	<u>\$ 49</u>	<u>\$ 5,167</u>

(a) Interest expense on capital lease obligations is recorded as rent expense.

(6) Asset Retirement Obligations

PacifiCorp records asset retirement obligation liabilities for long-lived physical assets that qualify as legal obligations. PacifiCorp estimates its asset retirement obligation liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. PacifiCorp then records an asset retirement obligation asset associated with the liability. The asset retirement obligation assets are depreciated over their expected lives and the asset retirement obligation liabilities are accreted to the projected spending date. Changes in estimates could occur due to plan revisions, changes in estimated costs and changes in timing of the performance of reclamation activities.

PacifiCorp does not recognize liabilities for asset retirement obligations for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain transmission and distribution and other assets cannot currently be estimated and no amounts are recognized in the financial statements other than those included in the accumulated provision for depreciation as established in approved depreciation rates.

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The following table describes the changes to PacifiCorp's asset retirement obligation liability for the years ended December 31, 2007 and 2006 (in millions):

	December 31, 2007	December 31, 2006
Liability recognized at beginning of period	\$ 86	\$ 62
Liabilities incurred	1	29
Liabilities settled	(6)	(5)
Revisions in cash flow (a)	(11)	(4)
Accretion expense (b)	<u>5</u>	<u>4</u>
Asset retirement obligation	<u>\$ 75</u>	<u>\$ 86</u>

- (a) Results from changes in the timing and amounts of estimated cash flows for certain plant reclamation.
- (b) PacifiCorp records the accretion expense of asset retirement obligations as either a regulatory asset or (liability).

(7) Risk Management and Hedging Activities

PacifiCorp is exposed to the impact of market fluctuations in commodity prices, principally natural gas and electricity. Interest rate risk exists on variable rate debt, commercial paper and future debt issuances. PacifiCorp employs established policies and procedures to manage its risks associated with these market fluctuations using various commodity and financial derivative instruments, including forward contracts, swaps and options. The risk management process established by PacifiCorp is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in its business. PacifiCorp's portfolio of energy derivatives is substantially used for non-trading purposes. As of December 31, 2007 and 2006, PacifiCorp had no financial derivatives in effect relating to interest rate exposure.

The following table summarizes the various derivative mark-to-market positions included in the Comparative Balance Sheet as of December 31, 2007 (in millions):

	Derivative Net Assets (Liability)			Net Regulatory Assets (Liabilities)	Accumulated Other Comprehensive (Income) Loss (a)
	Assets	Liabilities	Total		
Commodity	\$ 357	\$ (614)	\$ (257)	\$ 257	\$ -
Foreign currency	<u>1</u>	<u>-</u>	<u>1</u>	<u>(1)</u>	<u>-</u>
	<u>\$ 358</u>	<u>\$ (614)</u>	<u>\$ (256)</u>	<u>\$ 256</u>	<u>\$ -</u>
Current	\$ 143	\$ (117)	\$ 26		
Non-current	<u>215</u>	<u>(497)</u>	<u>(282)</u>		
Total	<u>\$ 358</u>	<u>\$ (614)</u>	<u>\$ (256)</u>		

- (a) Before income taxes.

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The following table summarizes the various derivative mark-to-market positions included in the Comparative Balance Sheet as of December 31, 2006 (in millions):

	Derivative Net Assets (Liability)			Net Regulatory Assets (Liabilities)	Accumulated Other Comprehensive (Income) Loss (a)
	Assets	Liabilities	Total		
Commodity	\$ 383	\$ (614)	\$ (231)	\$ 233	\$ (3)
Foreign currency	<u>3</u>	<u>-</u>	<u>3</u>	<u>(3)</u>	<u>-</u>
	<u>\$ 386</u>	<u>\$ (614)</u>	<u>\$ (228)</u>	<u>\$ 230</u>	<u>\$ (3)</u>
Current	\$ 151	\$ (110)	\$ 41		
Non-current	<u>235</u>	<u>(504)</u>	<u>(269)</u>		
Total	<u>\$ 386</u>	<u>\$ (614)</u>	<u>\$ (228)</u>		

(a) Before income taxes.

Commodity Price Risk

PacifiCorp is exposed to market risk due to the variations in the price of fuel used for generation and the price of wholesale electricity to be purchased or sold. To manage this commodity price risk, as well as to optimize the utilization of power generation assets and related contracts, PacifiCorp enters into forward purchases and sales. Such energy purchase and sales activities are governed by PacifiCorp's risk management policy.

PacifiCorp makes continuing projections of future retail and wholesale loads and future resource availability to meet these loads based on a number of criteria, including historical load and forward market prices and other economic information and experience. Based on these projections, PacifiCorp purchases and sells electricity on a forward yearly, quarterly, monthly, daily and hourly basis to match actual resources to actual energy requirements. This process involves hedging transactions, which include the purchase and sale of firm energy under long-term contracts, forward physical contracts or financial contracts for the purchase and sale of a specified amount of energy at a specified price over a given period of time.

PacifiCorp manages its exposure to increases in natural gas supply costs through forward commitments for the purchase of physical natural gas at fixed prices and financial swap energy contracts that settle in cash based on the difference between a fixed price that PacifiCorp pays and a floating market-based price that PacifiCorp receives.

Derivative Instruments

Forward physical and financial swap energy contracts that do not qualify for the exemptions afforded by GAAP are accounted for as derivatives and are recorded in the Comparative Balance Sheet as assets or liabilities measured at estimated fair value. Where PacifiCorp's derivative instruments are subject to a master netting agreement and the criteria of FIN 39, *Offsetting of Amounts Related to Certain Contracts – An Interpretation of APB Opinion No. 10 and FASB Statement No. 105*, are met, PacifiCorp presents its derivative assets and liabilities, as well as accompanying receivables and payables, on a net basis in the Comparative Balance Sheet. For those energy contracts that are probable of recovery in rates, the unrealized gains and losses on derivative instruments are recorded as a net regulatory asset or liability.

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Realized gains and losses on contracts that qualify as normal purchases and normal sales under GAAP (and therefore exempted from fair value accounting) are reflected in the Statement of Income at the contract settlement date.

Unrealized gains and losses on derivative contracts held for trading purposes are presented on a net basis in the Statement of Income as Miscellaneous nonoperating income. Unrealized gains and losses on electricity and natural gas derivative contracts not held for trading purposes are presented in the Statement of Income as Miscellaneous nonoperating income for unrealized gains and Other deductions for unrealized losses. Realized gains and losses on derivative contracts held for trading purposes are presented on a net basis in the Statement of Income as Revenue. Realized gains and losses on physically settled derivative contracts not held for trading purposes are presented in the Statement of Income as revenues for sales contracts and as Operation expenses for purchase contracts. Realized gains and losses on non-physically settled forward purchase and sale derivative contracts not held for trading purposes are presented on a gross basis in the Statement of Income as Revenues for gains and Operation expenses for losses. Realized gains and losses on financial swap energy contracts are presented in the Statement of Income as Operation expenses.

Cash Flow Hedging

In order to reduce the impact of fluctuations in forward prices of electricity and natural gas on PacifiCorp's results of operations, PacifiCorp initiated cash flow hedging in April 2006 for a portion of its derivative contracts, primarily electricity sales and natural gas purchase contracts. Changes in the fair value of derivative contracts designated as cash flow hedges are recorded as Accumulated other comprehensive income to the extent the hedges are effective in offsetting changes in future cash flows for forecasted electricity and natural gas purchase and sales transactions. Amounts included in Accumulated other comprehensive income are reclassified to the Statement of Income when the forecasted sale or purchase transaction is recognized in earnings, or when it is probable that the forecasted transaction will not occur. Hedge ineffectiveness and reclassifications from Accumulated other comprehensive income to earnings are presented in Miscellaneous nonoperating income and Other deductions.

Summary of Activity

The following table summarizes the amount of the pre-tax unrealized gains and losses included within the Statement of Income associated with changes in the fair value of PacifiCorp's derivative contracts that are not included in rates (in millions):

	Years Ended December 31,	
	2007	2006 (a)
Other income:		
Miscellaneous nonoperating income (421)	\$ (163)	\$ (476)
Other income deductions:		
Other deductions (426.5)	<u>161</u>	<u>527</u>
Total unrealized (gain) loss on derivative contracts	<u>\$ (2)</u>	<u>\$ 51</u>

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- (a) During the year ended December 31, 2006, PacifiCorp reached a new general rate case stipulation with several parties in Utah and received approval from the OPUC for a new general rate case settlement in Oregon. Utah and Oregon together account for approximately 70% of PacifiCorp's retail electric operating revenues. Based on management's consideration of the two new rate settlements, as well as the power cost recovery adjustment mechanisms approved in Wyoming and California earlier in 2006, PacifiCorp changed its estimate of the contracts receiving recovery in rates. Effective July 21, 2006, PacifiCorp recorded a \$40 million decrease in net regulatory assets for previously recorded net unrealized gains related to contracts that it determined were probable of being recovered in rates with a corresponding pre-tax charge to net income of \$44 million and a pre-tax increase to Accumulated other comprehensive income of \$4 million.

Fair Value Calculations

PacifiCorp bases its forward price curves upon market price quotations when available and bases them on internally developed and commercial models, with internal and external fundamental data inputs, when market quotations are unavailable. Market quotes are obtained from independent energy brokers, as well as direct information received from third-party offers and actual transactions executed by PacifiCorp. Price quotations for certain major electricity trading hubs are generally readily obtainable for the first six years and therefore PacifiCorp's forward price curves for those locations and periods reflect observable market quotes. However, in the later years or for locations that are not actively traded, forward price curves must be developed. For short-term contracts at less actively traded locations, prices are modeled based on observed historical price relationships with actively traded locations. For long-term contracts extending beyond six years, the forward price curve (beyond the first six years) is based upon the use of a fundamentals model (cost-to-build approach) due to the limited information available. The fundamentals model is updated as warranted, at least quarterly, to reflect changes in the market, such as long-term natural gas prices and expected inflation rates.

Short-term contracts, without explicit or embedded optionality, are valued based upon the relevant portion of the forward price curve. Contracts with explicit or embedded optionality are valued by separating each contract into its physical and financial forward, swap and option components. Forward and swap components are valued against the appropriate forward price curve. Options components are valued using Black-Scholes-type option models, such as European option, Asian option, spread option and best-of option, with the appropriate forward price curve and other inputs.

Foreign Currency Derivatives

PacifiCorp has entered into an agreement with a turbine supplier related to a wind plant under construction that requires PacifiCorp to make certain payments in Euros. To mitigate the related exposure to fluctuations in foreign currency exchange rates, PacifiCorp entered into forward contracts to purchase Euros at a fixed price of United States Dollars. There is one remaining settlement date of March 31, 2008 that corresponds to the final payment to be made in Euros under the supply agreement. The forward contracts qualify as derivative instruments. As the cost of the associated wind plant is expected to be recovered in rates, the unrealized gain on this contract was recorded as a net regulatory asset. The unrealized gain was \$1 million and \$3 million at December 31, 2007 and 2006, respectively.

Weather Derivatives

PacifiCorp had a non-exchange-traded streamflow weather derivative contract to reduce PacifiCorp's exposure to variability in weather conditions that affect hydroelectric generation. The contract expired on September 30, 2006. PacifiCorp paid an annual premium in return for the right to make or receive payments if streamflow levels were above or below certain thresholds. PacifiCorp recognized a loss of \$12 million during the year ended December 31, 2006. PacifiCorp currently has no streamflow or other weather derivative contracts.

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(8) **Income Taxes**

Income tax expense (benefit) consists of the following (in millions):

	Years ended December 31,	
	2007	2006
Current:		
Federal	\$ 145	\$ 132
State	<u>18</u>	<u>12</u>
Total	<u>163</u>	<u>144</u>
Deferred:		
Federal	51	20
State	<u>7</u>	<u>1</u>
Total	<u>58</u>	<u>21</u>
Investment tax credits	<u>(8)</u>	<u>(8)</u>
Total income tax expense	<u>\$ 213</u>	<u>\$ 157</u>

A reconciliation of the federal statutory tax rate to the effective tax rate applicable to income before income tax expense follows:

	Years ended December 31,	
	2007	2006
Federal statutory rate	35%	35%
State taxes, net of federal benefit	3	3
Effect of regulatory treatment of depreciation differences	2	4
Tax reserves	(2)	(2)
Tax credits	(3)	(4)
Other	<u>(3)</u>	<u>(2)</u>
Effective income tax rate	<u>32%</u>	<u>34%</u>

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The net deferred tax liability consists of the following (in millions):

	<u>December 31, 2007</u>	<u>December 31, 2006</u>
Deferred tax assets:		
Employee benefits	139	294
Derivative contracts	107	102
Regulatory liability	44	320
Other deferred tax assets	<u>142</u>	<u>104</u>
	<u>432</u>	<u>820</u>
Deferred tax liabilities:		
Property, plant and equipment	(1,374)	(1,510)
Regulatory assets	(591)	(727)
Derivative contract regulatory assets	(97)	(87)
Other deferred tax liabilities	<u>(65)</u>	<u>(110)</u>
	<u>(2,127)</u>	<u>(2,434)</u>
Net deferred tax liability	<u>\$ (1,695)</u>	<u>\$ (1,614)</u>

As of December 31, 2007 and December 31, 2006, PacifiCorp had no federal or state net operating loss carryforwards.

The sale of PacifiCorp to MEHC on March 21, 2006 triggered the recognition of a deferred intercompany gain or loss for tax purposes. The recognition of the tax effects of this item is considered to have occurred immediately prior to the closing of the sale of PacifiCorp while it was part of the PHI consolidated group. However, no adjustments have been recorded as PacifiCorp is not yet able to estimate the amount of the tax effect, if any, or determine a range of the potential tax effect. As the transaction was deemed to be with shareholders and as a result of formal agreements among PacifiCorp, MEHC, PHI and ScottishPower, PacifiCorp does not believe any adjustments resulting from the tax effect of a deferred intercompany gain or loss will have a material impact on its financial results.

PacifiCorp adopted FIN 48 effective January 1, 2007, resulting in a net increase in its asset for uncertain tax positions of \$13 million, which was offset by an increase in beginning retained earnings in the Comparative Balance Sheet.

PacifiCorp had a net asset of \$9 million for uncertain tax positions at December 31, 2007 that, if recognized, would have an impact on the effective tax rate.

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NOTES TO FINANCIAL STATEMENTS (Continued)			

(9) **Preferred Stock**

PacifiCorp's preferred stock, not subject to mandatory redemption, was as follows (shares in thousands, dollars in millions, except per share amounts):

	Redemption Price Per Share	December 31, 2007		December 31, 2006	
		Shares	Amount	Shares	Amount
Series:					
Serial Preferred,					
\$100 stated value,					
3,500 shares authorized					
4.52%	\$ 103.5	2	\$ -	2	\$ -
4.56	102.3	85	8	85	8
4.72	103.5	70	7	70	7
5.00	100.0	42	4	42	4
5.40	101.0	66	6	66	6
6.00	Non-redeemable	6	1	6	1
7.00	Non-redeemable	18	2	18	2
5% Preferred, \$100 stated					
value, 127 shares					
authorized	110.0	126	13	126	13
		<u>415</u>	<u>\$ 41</u>	<u>415</u>	<u>\$ 41</u>

Generally, preferred stock is redeemable at stipulated prices plus accrued dividends, subject to certain restrictions. In the event of voluntary liquidation, all preferred stock is entitled to stated value or a specified preference amount per share plus accrued dividends. Upon involuntary liquidation, all preferred stock is entitled to stated value plus accrued dividends. Dividends on all preferred stock are cumulative. Holders also have the right to elect members to the PacifiCorp board of directors in the event dividends payable are in default in an amount equal to four full quarterly payments.

Dividends declared but unpaid on preferred stock were \$1 million at December 31, 2007 and 2006.

(10) **Common Shareholder's Equity**

Appropriated Retained Earnings

In accordance with the requirements of certain hydroelectric relicensing projects, at December 31, 2007, PacifiCorp had \$4 million in Appropriated retained earnings – amortization reserve, federal.

Common Shareholder's Equity

Through PPW Holdings LLC, MEHC is the sole shareholder of PacifiCorp's common stock. The state regulatory orders that authorized the acquisition of PacifiCorp by MEHC contain restrictions on PacifiCorp's ability to pay dividends to the extent that they would reduce PacifiCorp's common stock equity below specified percentages of defined capitalization.

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As of December 31, 2007, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to either PPW Holdings LLC or MEHC without prior state regulatory approval to the extent that it would reduce PacifiCorp's common stock equity below 48.25% of its total capitalization, excluding short-term debt and current maturities of long-term debt. After December 31, 2008, this minimum level of common equity declines annually to 44.0% after December 31, 2011. The terms of this commitment treat 50.0% of PacifiCorp's remaining balance of preferred stock in existence prior to the acquisition of PacifiCorp by MEHC as common equity. As of December 31, 2007, PacifiCorp's actual common stock equity percentage, as calculated under this measure, exceeded the minimum threshold.

These commitments also restrict PacifiCorp from making any distributions to either PPW Holdings LLC or MEHC if PacifiCorp's unsecured debt rating is BBB- or lower by Standard & Poor's Rating Services or Fitch Ratings or Baa3 or lower by Moody's Investor Service, as indicated by two of the three rating services. At December 31, 2007, PacifiCorp's unsecured debt rating was BBB+ by Standard & Poor's Rating Services and Fitch Ratings and Baa1 by Moody's Investor Service.

PacifiCorp is also subject to maximum debt-to-total capitalization percentage under various financing agreements as further discussed in Notes 4 and 5.

(11) Contingencies

Legal Matters

PacifiCorp is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. PacifiCorp does not believe that such normal and routine litigation will have a material effect on its financial results. PacifiCorp is also involved in other kinds of legal actions, some of which assert or may assert claims or seek to impose fines and penalties in substantial amounts and are described below.

In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a complaint against PacifiCorp in the federal district court in Cheyenne, Wyoming, alleging violations of the Wyoming state opacity standards at PacifiCorp's Jim Bridger plant in Wyoming. Under Wyoming state requirements, which are part of the Jim Bridger plant's Title V permit and are enforceable by private citizens under the federal Clean Air Act, a potential source of pollutants such as a coal-fired generating facility must meet minimum standards for opacity, which is a measurement of light that is obscured in the flue of a generating facility. The complaint alleges thousands of violations of six-minute compliance periods and seeks an injunction ordering the Jim Bridger plant's compliance with opacity limits, civil penalties of \$32,500 per day per violation, and the plaintiffs' costs of litigation. The court granted a motion to bifurcate the trial into separate liability and remedy phases. A five-day trial on the liability phase is scheduled to begin on April 21, 2008. The remedy-phase trial has not yet been set. PacifiCorp believes it has a number of defenses to the claims. PacifiCorp intends to vigorously oppose the lawsuit but cannot predict its outcome at this time. PacifiCorp has already committed to invest at least \$812 million in pollution control equipment at its generating facilities, including the Jim Bridger plant. This commitment is expected to significantly reduce system-wide emissions, including emissions at the Jim Bridger plant.

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Environmental Matters

PacifiCorp is subject to numerous environmental laws, including the federal Clean Air Act, related air quality standards promulgated by the Environmental Protection Agency and various state air quality laws; the Endangered Species Act, particularly as it relates to certain endangered species of fish; the Comprehensive Environmental Response, Compensation and Liability Act, and similar state laws relating to environmental cleanups; the Resource Conservation and Recovery Act and similar state laws relating to the storage and handling of hazardous materials; and the Clean Water Act, and similar state laws relating to water quality. These laws have the potential for impacting PacifiCorp's operations. Specifically, the Clean Air Act will likely continue to impact the operations of PacifiCorp's generating facilities and will likely require PacifiCorp to reduce emissions from those facilities through the installation of additional or improved emission controls, the purchase of additional emission allowances, or some combination thereof. As of December 31, 2007, PacifiCorp's environmental contingencies principally consist of air quality matters. Pending or proposed air regulations would, if enacted, require PacifiCorp to reduce its electricity plant emissions of sulfur dioxide, nitrogen oxide and other pollutants at its generating plants below current levels. PacifiCorp believes it is in material compliance with current environmental requirements.

PacifiCorp's policy is to accrue environmental cleanup-related costs of a non-capital nature when those costs are believed to be probable and can be reasonably estimated. The quantification of environmental exposures is based on assessments of many factors, including changing laws and regulations, advancements in environmental technologies, the quality of information available related to specific sites, the assessment stage of each site investigation, preliminary findings and the length of time involved in remediation or settlement, PacifiCorp's proportionate share and any coverage provided by insurance policies. Remediation costs that are fixed and determinable have been discounted to their present value using credit-adjusted, risk-free discount rates based on the expected future annual borrowing costs of PacifiCorp. The liability recorded was \$13 million at December 31, 2007 and \$20 million at December 31, 2006 and is included in Deferred credits in the Comparative Balance Sheet. The December 31, 2007 recorded liability included \$3 million of discounted liabilities. Had none of the liabilities included in the \$13 million balance recorded at December 31, 2007 been discounted, the total would have been \$14 million. The expected undiscounted payments for each of the years ending December 31, 2008 through 2012 and thereafter are as follows: \$2 million in 2008, \$- million in 2009, \$1 million in 2010, \$- million in 2011, \$- million in 2012 and \$11 million thereafter.

It is possible that future findings or changes in estimates could require that additional amounts be accrued. Should current circumstances change, it is possible that PacifiCorp could incur an additional undiscounted obligation of up to approximately \$3 million relating to existing sites. However, management believes that completion or resolution of these matters will have no material adverse effect on PacifiCorp's financial position, results of operations or cash flows.

Hydroelectric Relicensing

PacifiCorp's hydroelectric portfolio consists of 47 plants with an aggregate plant net owned capacity of 1,158 MW. The FERC regulates 98% of the net capacity of this portfolio through 16 individual licenses. Several of PacifiCorp's hydroelectric projects are in some stage of relicensing with the FERC. Hydroelectric relicensing and the related environmental compliance requirements and litigation are subject to uncertainties. PacifiCorp expects that future costs relating to these matters may be significant and will consist primarily of additional relicensing costs, operations and maintenance expense, and capital expenditures. Electricity generation reductions may result from the additional environmental requirements. PacifiCorp had incurred \$89 million and \$79 million in costs as of December 31, 2007 and 2006, respectively, for ongoing hydroelectric relicensing, which are reflected in Construction work-in-progress in the Comparative Balance Sheet.

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In February 2004, PacifiCorp filed with the FERC a final application for a new license to operate the 169-MW (nameplate rating) Klamath hydroelectric project in anticipation of the March 2006 expiration of the existing license. PacifiCorp is currently operating under an annual license issued by the FERC and expects to continue to operate under annual licenses until the new operating license is issued. As part of the relicensing process, the United States Departments of Interior and Commerce filed proposed licensing terms and conditions with the FERC in March 2006, which proposed that PacifiCorp construct upstream and downstream fish passage facilities at the Klamath hydroelectric project's four mainstem dams. In April 2006, PacifiCorp filed alternatives to the federal agencies' proposal and requested an administrative hearing to challenge some of the federal agencies' factual assumptions supporting their proposal for the construction of the fish passage facilities. A hearing was held in August 2006 before an administrative law judge. The administrative law judge issued a ruling in September 2006 generally supporting the federal agencies' factual assumptions. In January 2007, the United States Departments of Interior and Commerce filed modified terms and conditions consistent with the March 2006 filings and rejected the alternatives proposed by PacifiCorp. PacifiCorp is prepared to meet and implement the federal agencies' terms and conditions as part of the project's relicensing. However, PacifiCorp expects to continue in settlement discussions with various parties in the Klamath Basin area who have intervened with the FERC licensing proceeding to try to achieve a mutually acceptable outcome for the project.

Also, as part of the relicensing process, the FERC is required to perform an environmental review. In September 2006, the FERC issued its draft environmental impact statement on the Klamath hydroelectric project license. PacifiCorp filed comments on the draft statement by the close of the public comment period on December 1, 2006. Subsequently, in November 2007, the FERC issued its final environmental impact statement. The United States Fish and Wildlife Service and the National Marine Fisheries Service issued final biological opinions in December 2007 analyzing the hydroelectric project's impact on endangered species under the proposed new FERC license. The United States Fish and Wildlife Service asserts the hydroelectric project is currently not covered by previously issued biological opinions, and that consultation under the Endangered Species Act is required by the issuance of annual license renewals. PacifiCorp disputes these assertions, and believes federal case law is clear that consultation on annual FERC licenses is not required. PacifiCorp will need to obtain water quality certifications from Oregon and California prior to the FERC issuing a final license. PacifiCorp currently has applications pending before each state.

In the relicensing of the Klamath hydroelectric project, PacifiCorp had incurred \$48 million and \$42 million in costs at December 31, 2007 and 2006, respectively, which are reflected in Construction work-in-progress in the Comparative Balance Sheet. While the costs of implementing new license provisions cannot be determined until such time as a new license is issued, such costs could be material.

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FERC Issues

California Refund Case

In June 2007, the FERC approved PacifiCorp's settlement and release of claims agreement ("Settlement") with Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, the People of the State of California, ex rel. Edmund G. Brown Jr., Attorney General, the California Electricity Oversight Board, and the California Public Utilities Commission (collectively, the "California Parties"), certain of which purchased energy in the California Independent System Operator ("ISO") and the California Power Exchange ("PX") markets during past periods of high energy prices in 2000 and 2001. The Settlement, which was executed by PacifiCorp in April 2007, settles claims brought by the California Parties against PacifiCorp for refunds and remedies in numerous related proceedings (together, the "FERC Proceedings"), as well as certain potential civil claims, arising from events and transactions in Western United States energy markets during the period January 2000 through June 2001 (the "Refund Period"). Under the Settlement, PacifiCorp made cash payments to escrows controlled by the California Parties in the amount of \$16 million in April 2007, and upon FERC approval of the agreement in June 2007, PacifiCorp allowed the PX to release an additional \$12 million to such escrows, which represented PacifiCorp's estimated unpaid receivable from the transactions in the PX and ISO markets during the Refund Period, plus interest. The monies held in escrow are for distribution to buyers from the ISO and PX markets that purchased power during the Refund Period. The agreement provides for the release of claims by the California Parties (as well as additional parties that join in the Settlement) against PacifiCorp for refunds, disgorgement of profits, or other monetary or non-monetary remedies in the FERC Proceedings, and provides a mutual release of claims for civil damages and equitable relief.

Northwest Refund Case

In June 2003, the FERC terminated its proceeding relating to the possibility of requiring refunds for wholesale spot-market bilateral sales in the Pacific Northwest between December 2000 and June 2001. The FERC concluded that ordering refunds would not be an appropriate resolution of the matter. In November 2003, the FERC issued its final order denying rehearing. Several market participants filed petitions in the United States Court of Appeals for the Ninth Circuit (the "Ninth Circuit") for review of the FERC's final order. In August 2007, the Ninth Circuit issued its order on this appeal, concluding that the FERC failed to adequately explain how it considered or examined new evidence showing intentional market manipulation in California and its potential ties to the Pacific Northwest and that the FERC should not have excluded from the Pacific Northwest refund proceeding purchases of energy made by the California Energy Resources Scheduling ("CERS") division in the Pacific Northwest spot market. The Ninth Circuit remanded the case to the FERC to (i) address the new market manipulation evidence in detail and account for it in any future orders regarding the award or denial of refunds in the proceedings, (ii) include sales to CERS in its analysis, and (iii) further consider its refund decision in light of related, intervening opinions of the court. The Ninth Circuit offered no opinion on the FERC's findings based on the record established by the administrative law judge and did not rule on the merits of the FERC's November 2003 decision to deny refunds. Due to the remand, PacifiCorp cannot predict the impact of this ruling at this time.

(12) Guarantees and Other Commitments

Guarantees

PacifiCorp is generally required to obtain state regulatory commission approval prior to guaranteeing debt or obligations of other parties. The following represent the indemnification obligations of PacifiCorp at December 31, 2007.

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PacifiCorp has made certain commitments related to the decommissioning or reclamation of certain jointly owned facilities and mine sites. The decommissioning commitments require PacifiCorp to pay a proportionate share of the decommissioning costs based upon percentage of ownership. The mine reclamation commitments require PacifiCorp to pay the mining entity a proportionate share of the mine's reclamation costs based on the amount of coal purchased by PacifiCorp. In the event of default by any of the other joint participants, PacifiCorp potentially may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. PacifiCorp has recorded its estimated share of the decommissioning and reclamation commitments.

In connection with the sale of PacifiCorp's Montana service territory, PacifiCorp entered into a purchase and sale agreement with Flathead Electric Cooperative in October 1998. Under the agreement, PacifiCorp agreed to indemnify Flathead Electric Cooperative for losses, if any, occurring after the closing date and arising as a result of certain breaches of warranty or covenants. The indemnification has a cap of \$10 million until October 2008 and a cap of \$5 million thereafter (less expended costs to date). Two indemnity claims relating to environmental issues have been tendered, but remediation costs for these claims, if any, are not expected to be material.

Unconditional Purchase Obligations (in millions)

	Payments Due During the Year Ending December 31,						Total
	2008	2009	2010	2011	2012	Thereafter	
Construction	\$ 342	\$ 6	\$ 1	\$ -	\$ -	\$ -	\$ 349
Operating leases	9	4	4	3	3	35	58
Purchased electricity	734	487	414	256	182	1,874	3,947
Transmission	61	64	60	54	47	404	690
Fuel	607	531	445	276	118	1,104	3,081
Other	156	84	97	102	56	830	1,325
Total commitments	<u>\$ 1,909</u>	<u>\$ 1,176</u>	<u>\$ 1,021</u>	<u>\$ 691</u>	<u>\$ 406</u>	<u>\$ 4,247</u>	<u>\$ 9,450</u>

Construction

PacifiCorp has an ongoing construction program to meet increased electricity usage, customer growth and system reliability objectives. At December 31, 2007, PacifiCorp had estimated long-term unconditional purchase obligations related to the construction of five new wind plants.

Operating Leases

PacifiCorp leases offices, certain operating facilities, land and equipment under operating leases that expire at various dates through the year ending December 31, 2092. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. These leases generally require PacifiCorp to pay for insurance, taxes and maintenance applicable to the leased property. Excluded from the operating lease payments above are any power purchase agreements that meet the definition of an operating lease.

Net rent expense, including that related to obligations accounted for as capital leases for balance sheet presentation, was \$29 million during the year ended December 31, 2007 and \$26 million during the year ended December 31, 2006.

Minimum non-cancelable sublease rent payments expected to be received through the year ended December 31, 2018 total \$21 million.

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Purchased Electricity

As part of its energy resource portfolio, PacifiCorp acquires a portion of its electricity through long-term purchases and/or exchange agreements. Included in the purchased electricity payments above are any power purchase agreements that meet the definition of an operating lease.

Included in the minimum fixed annual payments for purchased electricity above are commitments to purchase electricity from several hydroelectric projects under long-term arrangements with public utility districts. These purchases are made on a "cost-of-service" basis for a stated percentage of project output and for a like percentage of project operating expenses and debt service. These costs are included in Operation expenses in the Statement of Income. PacifiCorp is required to pay its portion of operating costs and its portion of the debt service, whether or not any electricity is produced.

At December 31, 2007, PacifiCorp's share of long-term arrangements with public utility districts was as follows (in millions):

	Year Contract Expires	Nameplate (MW)	Percentage of Output	Annual Costs (a)
Generating Facility:				
Wanapum	2009	194	19%	\$ 10
Rocky Reach	2011	69	5	4
Priest Rapids	2045	63	7	3
Wells	2018	53	7	3
Total		<u>379</u>		<u>\$ 20</u>

(a) Includes debt service totaling \$11 million.

PacifiCorp's minimum debt service and estimated operating obligations included in purchased electricity above for the years ending December 31 are as follows (in millions):

	Minimum Debt Service	Operating Obligations
2008	\$ 11	\$ 12
2009	11	12
2010	5	6
2011	5	6
2012	3	4
Thereafter	<u>64</u>	<u>122</u>
	<u>\$ 99</u>	<u>\$ 162</u>

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PacifiCorp has a 4% entitlement to the generation of the Intermountain Power Project, located in central Utah, through a power purchase agreement. PacifiCorp and the City of Los Angeles have agreed that the City of Los Angeles will purchase capacity and energy from PacifiCorp's 4% entitlement of the Intermountain Power Project at a price equivalent to 4% of the expenses and debt service of the project.

Fuel

PacifiCorp has "take or pay" coal and natural gas contracts that require minimum payments.

Other

Unconditional purchase obligations, as defined by accounting standards, are those long-term commitments that are non-cancelable or cancelable only under certain conditions. PacifiCorp has such commitments related to legal or contractual asset retirement obligations, environmental obligations, hydroelectric obligations, equipment maintenance and various other service and maintenance agreements. Also included are contributions expected to be made to the PacifiCorp Retirement Plan during the year ending December 31, 2008 as disclosed in Note 13 below.

(13) Employee Benefit Plans

PacifiCorp sponsors defined benefit pension plans that cover the majority of its employees and also provides certain postretirement health care and life insurance benefits through various plans for eligible retirees. In addition, PacifiCorp sponsors an employee savings plan.

As a result of the sale of PacifiCorp to MEHC, plan participants that were employees or retirees of certain ScottishPower affiliates and a former PacifiCorp mining subsidiary ceased to participate in PacifiCorp's plans. This separation resulted in a net \$4 million reduction in Other paid-in capital during the year ended December 31, 2006.

Pension and Other Postretirement Plans

PacifiCorp's pension plans include a non-contributory defined benefit pension plan, the PacifiCorp Retirement Plan (the "Retirement Plan"); the Supplemental Executive Retirement Plan (the "SERP"); and certain multi-employer and joint trust union plans to which PacifiCorp contributes on behalf of certain bargaining units. Benefits for union employees covered under the Retirement Plan are based on the employee's years of service and average monthly pay in the 60 consecutive months of highest pay out of the last 120 months, with adjustments to reflect benefits estimated to be received from social security.

Effective June 1, 2007, PacifiCorp switched from a traditional final average pay formula for the Retirement Plan to a cash balance formula for its non-union employees. As a result of the change, benefits under the traditional final average pay formula were frozen as of May 31, 2007 for non-union employees, and PacifiCorp's pension liability and regulatory assets each decreased by \$111 million. Non-union employees hired on or after January 1, 2008 will not be eligible to participate in PacifiCorp's Retirement Plan. These non-union employees will be eligible to receive enhanced benefits under PacifiCorp's defined contribution plan.

Effective December 31, 2007, Local Union No. 659 of the International Brotherhood of Electrical Workers ("Local 659") elected to cease participation in the Retirement Plan and participate only in PacifiCorp's defined contribution plan with enhanced benefits. As a result of this election, the Local 659 participants' benefits were frozen as of December 31, 2007.

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The cost of other postretirement benefits, including health care and life insurance benefits for eligible retirees, is accrued over the active service period of employees. PacifiCorp funds these other postretirement benefits through a combination of funding vehicles. PacifiCorp also contributes to joint trust union plans for postretirement benefits offered to certain bargaining units.

Plan assets and benefit obligations are measured three months prior to PacifiCorp's fiscal year end. Accordingly, plan assets and benefit obligations were measured as of September 30. The market-related value of plan assets, among other factors, is used to determine expected return on plan assets. The market-related value of plan assets is calculated by spreading the difference between expected and actual investment returns over a five-year period beginning after the first year in which they occur. As differences between expected and actual investment returns are recognized, they are included in the Amortization of prior year loss component of Net periodic benefit cost.

The following disclosures were generally taken directly from PacifiCorp's Form 10-K filed with the SEC in February 2008. Net periodic benefit cost for the pension, including the SERP, and other postretirement benefit plans included the following components (in millions):

	Pension		Other Postretirement	
	Year Ended December 31, 2007	Nine-Month Period Ended December 31, 2006	Year Ended December 31, 2007	Nine-Month Period Ended December 31, 2006
Service cost (a)	\$ 29	\$ 22	\$ 7	\$ 7
Interest cost	71	56	33	25
Expected return on plan assets	(68)	(54)	(26)	(19)
Net amortization	23	23	19	15
Cost of termination benefits	1	2	-	-
Curtailment loss	-	1	-	-
Net periodic benefit cost (b)	<u>\$ 56</u>	<u>\$ 50</u>	<u>\$ 33</u>	<u>\$ 28</u>

- (a) Service cost excludes \$10 million of contributions to the multi-employer and joint trust union plans during the year ended December 31, 2007, \$6 million during the nine-month period ended December 31, 2006 and \$1 million during the year ended March 31, 2006.
- (b) Net periodic benefit cost for the three months ended March 31, 2006 was \$17 million for the pension plans and \$7 million for the other postretirement plans, resulting in total net periodic benefit cost for the year ended December 31, 2006 of \$67 million for the pension plans and \$35 million for the other postretirement plans.

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The following table is a reconciliation of the fair value of plan assets as of the end of the period (in millions):

	Pension		Other Postretirement	
	Year Ended December 31, 2007	Nine-Month Period Ended December 31, 2006	Year Ended December 31, 2007	Nine-Month Period Ended December 31, 2006
Plan assets at fair value, beginning of period	\$ 884	\$ 825	\$ 318	\$ 292
Employer contributions	80	79	46	30
Participant contributions	-	-	11	7
Actual return on plan assets	118	56	46	19
Benefits paid	(119)	(76)	(43)	(30)
Plan assets at fair value, end of period	<u>\$ 963</u>	<u>\$ 884</u>	<u>\$ 378</u>	<u>\$ 318</u>

The SERP has no plan assets; however, PacifiCorp has a Rabbi trust that holds corporate-owned life insurance and other investments to provide funding for the future cash requirements of the SERP. The cash surrender value of all of the policies included in the Rabbi trust, net of amounts borrowed against the cash surrender value, plus the fair market value of other Rabbi trust investments, was \$40 million and \$39 million at December 31, 2007 and 2006, respectively. These assets are not included in the plan assets in the above table. The portion of the pension plans' projected benefit obligation, included in the table below, related to the SERP was \$52 million and \$54 million at December 31, 2007 and 2006, respectively.

The following table is a reconciliation of the benefit obligations at the end of the period (in millions):

	Pension		Other Postretirement	
	Year Ended December 31, 2007	Nine-Month Period Ended December 31, 2006	Year Ended December 31, 2007	Nine-Month Period Ended December 31, 2006
Benefit obligation, beginning of period	\$ 1,333	\$ 1,342	\$ 566	\$ 582
Service cost	29	22	7	7
Interest cost	71	56	33	25
Participant contributions	-	-	11	7
Plan amendments	(130)	-	-	-
Actuarial gain	(74)	(13)	(40)	(25)
Benefits paid	(119)	(76)	(43)	(30)
Cost of termination benefits	1	2	-	-
Medicare Part D subsidy	-	-	2	-
Benefit obligation, end of period	<u>\$ 1,111</u>	<u>\$ 1,333</u>	<u>\$ 536</u>	<u>\$ 566</u>
Accumulated benefit obligation as of the measurement date	<u>\$ 1,061</u>	<u>\$ 1,165</u>		

The SERP's accumulated benefit obligation totaled \$52 million and \$53 million at December 31, 2007 and 2006, respectively.

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The funded status of the plans and the amounts recognized in the Comparative Balance Sheet are as follows (in millions):

	Pension		Other Postretirement	
	December 31, 2007	December 31, 2006	December 31, 2007	December 31, 2006
Plan assets at fair value, end of period	\$ 963	\$ 884	\$ 378	\$ 318
Less - Benefit obligation, end of period	<u>1,111</u>	<u>1,333</u>	<u>536</u>	<u>566</u>
Funded status	(148)	(449)	(158)	(248)
Contributions after the measurement date but before year-end	<u>-</u>	<u>-</u>	<u>12</u>	<u>27</u>
Amounts recognized in the Comparative Balance Sheet	<u>\$ (148)</u>	<u>\$ (449)</u>	<u>\$ (146)</u>	<u>\$ (221)</u>
Amounts recognized in the Comparative Balance Sheet:				
Other current liabilities	\$ (4)	\$ (4)	\$ -	\$ -
Pension and other post employment liabilities	<u>(144)</u>	<u>(445)</u>	<u>(146)</u>	<u>(221)</u>
Amounts recognized	<u>\$ (148)</u>	<u>\$ (449)</u>	<u>\$ (146)</u>	<u>\$ (221)</u>
Amounts not yet recognized as components of net periodic benefit cost:				
Net loss	\$ 250	\$ 400	\$ 45	\$ 109
Prior service cost (credit)	(115)	9	17	20
Net transition obligation	<u>3</u>	<u>5</u>	<u>60</u>	<u>72</u>
Total	<u>\$ 138</u>	<u>\$ 414</u>	<u>\$ 122</u>	<u>\$ 201</u>

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the year ended December 31, 2007 is as follows (in millions):

	Regulatory Asset	Accumulated Other Comprehensive Income	Total
<u>Pension</u>			
Balance, beginning of year	\$ 405	\$ 9	\$ 414
Prior service cost arising during the year	(129)	(1)	(130)
Net gain arising during the year	(121)	(2)	(123)
Net amortization	(23)	-	(23)
Total	<u>(273)</u>	<u>(3)</u>	<u>(276)</u>
Balance, end of year	<u>\$ 132</u>	<u>\$ 6</u>	<u>\$ 138</u>
	Regulatory Asset	Deferred Income Taxes	Total
<u>Other Postretirement</u>			
Balance, beginning of year	\$ 161	\$ 40	\$ 201
Net gain arising during the year	(47)	(13)	(60)
Net amortization	(19)	-	(19)
Total	<u>(66)</u>	<u>(13)</u>	<u>(79)</u>
Balance, end of year	<u>\$ 95</u>	<u>\$ 27</u>	<u>\$ 122</u>

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
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NOTES TO FINANCIAL STATEMENTS (Continued)			

The net loss, prior service cost and net transition obligation that will be amortized in 2008 into net periodic benefit cost are estimated to be as follows (in millions):

	Net Loss	Prior Service Cost	Net Transition Obligation	Total
Pension benefits	\$ 17	\$ (13)	\$ 3	\$ 7
Other postretirement benefits	-	3	12	15
Total	\$ 17	\$ (10)	\$ 15	\$ 22

Plan Assumptions

Assumptions used to determine benefit obligations and net benefit cost were as follows:

	Pension		Other Postretirement	
	Year Ended December 31, 2007	Nine-Month Period Ended December 31, 2006	Year Ended December 31, 2007	Nine-Month Period Ended December 31, 2006
Benefit obligations as of the measurement date:				
Discount rate	6.30%	5.85%	6.45%	6.00%
Rate of compensation increase	4.00	4.00	N/A	N/A
Net benefit cost for the period ended:				
Discount rate	5.76%	5.75%	6.00%	5.75%
Expected return on plan assets	8.00	8.50	8.00	8.50
Rate of compensation increase	4.00	4.00	N/A	N/A

Assumed health care cost trend rates as of the measurement date:

	Year Ended December 31, 2007	Nine-Month Period Ended December 31, 2006
Health care cost trend rate assumed for next year - under 65	9%	10%
Health care cost trend rate assumed for next year - over 65	7	8
Rate that the cost trend rate gradually declines to	5	5
Year that rate reaches the rate it is assumed to remain at - under 65	2012	2012
Year that rate reaches the rate it is assumed to remain at - over 65	2010	2010

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NOTES TO FINANCIAL STATEMENTS (Continued)			

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects (in millions):

	Increase (Decrease) in Expense	
	One Percentage-Point Increase	One Percentage-Point Decrease
Effect on total service and interest cost	\$ 3	\$ (2)
Effect on other postretirement benefit obligation	40	(33)

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be approximately \$70 million and \$27 million, respectively, for 2008. Also during 2008, PacifiCorp expects to contribute approximately \$11 million to the joint trust union plans.

Retirement Plan costs are funded annually by at least the minimum required amount but by no more than the maximum amount that can be deducted for federal income tax purposes. The Pension Protection Act of 2006 changes funding rules beginning in 2008 and may have the effect of making minimum pension funding requirements more volatile than they have been historically. Accordingly, PacifiCorp continually evaluates its funding strategies. PacifiCorp's policy is to contribute to its other postretirement benefit plan an amount equal to the net periodic cost.

PacifiCorp's expected benefit payments to participants for its pension and other postretirement plans for 2008 through 2012 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments			
	Pension	Gross	Other Postretirement Medicare Subsidy	Net of Subsidy
2008	\$ 89	\$ 38	\$ 3	\$ 35
2009	86	39	4	35
2010	91	40	4	36
2011	92	42	4	38
2012	99	42	5	37
2013 - 2017	535	232	31	201

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NOTES TO FINANCIAL STATEMENTS (Continued)			

Investment Policy and Asset Allocation

The Retirement Plan and other postretirement plan assets are managed and invested in accordance with all applicable requirements, including the Employee Retirement Income Security Act and the Internal Revenue Code. PacifiCorp employs an investment approach that primarily uses a mix of equities and fixed-income investments to maximize the long-term return of plan assets at a prudent level of risk. Risk tolerance is established through consideration of plan liabilities, plan funded status, and corporate financial condition. The investment portfolio contains a diversified blend of primarily equity, fixed-income and other alternative investments as shown in the table below. Equity investments are diversified across United States and foreign stocks, as well as growth and value companies, and small and large market capitalizations. Fixed-income investments are diversified across United States and foreign bonds. Other assets, such as private equity investments, are used to enhance long-term returns while improving portfolio diversification. PacifiCorp primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk through quarterly investment portfolio reviews, annual liability measurements and periodic asset/liability studies.

The assets for other postretirement benefits are composed of three different trust accounts. The 401(h) account is invested in the same manner as the assets of the Retirement Plan. Each of the two Voluntary Employees' Beneficiaries Association Trusts has its own investment allocation strategies.

PacifiCorp's asset allocation was as follows:

	Pension & Other Postretirement			Voluntary Employees' Beneficiaries Association Trust		
	December 31, 2007	December 31, 2006	Target	December 31, 2007	December 31, 2006	Target
Equity securities	56%	58%	53 – 57%	64%	65%	63 – 67%
Debt securities	35	35	33 – 37	36	35	33 – 37
Other	9	7	8 – 12	-	-	-
	<u>100%</u>	<u>100%</u>		<u>100%</u>	<u>100%</u>	

Defined Contribution Plan

PacifiCorp's employee savings plan qualifies as a tax-deferred arrangement under the Internal Revenue Code and covers substantially all employees. PacifiCorp's contributions to the employee savings plan were \$19 million during the year ended December 31, 2007 and \$21 million during the year ended December 31, 2006.

Severance

PacifiCorp has undertaken a review of its organization and workforce. As a result of the review, PacifiCorp incurred severance expense of \$4 million during the year ended December 31, 2007 and \$43 million during the year ended December 31, 2006.

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NOTES TO FINANCIAL STATEMENTS (Continued)			

(14) Fair Value of Financial Instruments

The carrying amounts of cash and cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximate fair value because of the short-term maturity of these instruments. Derivative instruments are recorded at their fair values, which are based upon published market indexes as adjusted for other market factors such as location pricing differences or internally developed models. Substantially all investments are carried at their fair values, which are based on quoted market prices.

The fair value of PacifiCorp's fixed-rate long-term debt, current maturities of long-term debt and preferred stock subject to mandatory redemption has been estimated based on quoted market prices. The carrying amount of variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying amount and estimated fair value of PacifiCorp's long-term debt and preferred stock subject to mandatory redemption, including the current portion (in millions):

	December 31, 2007		December 31, 2006	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	\$ 5,118	\$ 5,350	\$ 4,044	\$ 4,243
Preferred stock subject to mandatory redemption	-	-	38	38

(15) Related-Party Transactions

Transactions while owned by MEHC

As discussed in Note 1, PacifiCorp was acquired by a subsidiary of MEHC on March 21, 2006. The following describes PacifiCorp's transactions and balances with unconsolidated related parties while owned by MEHC.

In the ordinary course of business, PacifiCorp engages in various transactions with several of its affiliated companies. Services provided by PacifiCorp and charged to affiliates related primarily to the administrative services, financial statement preparation and direct-assigned employees. These receivables were \$- million at December 31, 2007 and \$1 million at December 31, 2006. Services provided by affiliates and charged to PacifiCorp related primarily to the transport of natural gas, relocation services, and administrative services provided under the intercompany administrative services agreement among MEHC and its affiliates. These payables were \$2 million at December 31, 2007 and \$1 million at December 31, 2006. These expenses totaled \$14 million during the year ended December 31, 2007 and \$8 million during the year ended December 31, 2006.

PacifiCorp has long-term transportation contracts with the Burlington Northern Santa Fe Railway ("BNSF"), in which PacifiCorp's ultimate parent company, Berkshire Hathaway, acquired a 17% ownership interest during 2007. At December 31, 2007, PacifiCorp had \$2 million of accounts payable to BNSF outstanding under these contracts, including indirect payables related to a jointly owned plant. Transportation costs under these contracts were \$31 million during the year ended December 31, 2007.

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NOTES TO FINANCIAL STATEMENTS (Continued)			

Effective March 21, 2006, PacifiCorp began participating in a captive insurance program provided by MEHC Insurance Services Ltd. ("MISL"), a wholly owned subsidiary of MEHC. MISL covers all or significant portions of the property damage and liability insurance deductibles in many of PacifiCorp's current policies, as well as overhead distribution and transmission line property damage. PacifiCorp has no equity interest in MISL and has no obligation to contribute equity or loan funds to MISL. Premium amounts are established based on a combination of actuarial assessments and market rates to cover loss claims, administrative expenses and appropriate reserves, but as a result of regulatory commitments are capped through December 31, 2010. Certain costs associated with the program are prepaid and amortized over the policy coverage period expiring March 20, 2008. Prepayments to MISL were \$2 million at December 31, 2007 and \$2 million at December 31, 2006. Receivables for claims were \$11 million at December 31, 2007 and \$8 million at December 31, 2006. Premium expenses were \$7 million during the year ended December 31, 2007 and \$6 million during the year ended December 31, 2006.

PacifiCorp is party to a tax-sharing agreement and is part of the Berkshire Hathaway consolidated tax return. As of December 31, 2007 and 2006, Prepayments included \$22 million and \$44 million, respectively, of income taxes receivable from PacifiCorp's parent company.

Transactions with Unconsolidated Subsidiaries of PacifiCorp

In the ordinary course of business, PacifiCorp engages in various transactions with its unconsolidated subsidiaries. Services provided by PacifiCorp and charged to its subsidiaries related primarily to management services, income taxes and labor. These receivables were \$1 million at December 31, 2007 and 2006. Services provided by subsidiaries and charged to PacifiCorp primarily related to coal purchases. These payables were \$9 million at December 31, 2007 and 2006. Expenses for these coal purchases were \$102 million for the year ended December 31, 2007 and \$94 million for the year ended December 31, 2006.

PacifiCorp is party to an umbrella loan agreement with one of its unconsolidated subsidiaries. Regulatory authorizations permit PacifiCorp to borrow from its subsidiaries (including those that are consolidated) without limitation and to loan each of these subsidiaries up to \$30 million at any one time, provided that the borrowings bear interest at rates that do not exceed the interest rates that PacifiCorp would otherwise incur externally. As of December 31, 2007 and 2006, affiliated notes receivable from unconsolidated subsidiaries were \$26 million and \$23 million, respectively, including interest.

Transactions while owned by ScottishPower

Under ScottishPower ownership, PacifiCorp engaged in various transactions with several of its former affiliated companies pursuant to ScottishPower's affiliated interest cross-charge policy. Revenues from these former affiliates related primarily to wheeling services and totaled \$2 million for the year ended December 31, 2006. Services provided by PacifiCorp and recharged to these former affiliates related primarily to administrative services, costs associated with retention agreements and severance benefits reimbursed by ScottishPower, and payroll costs and related benefits of PacifiCorp employees working on international assignment in the United Kingdom. These charges totaled \$2 million for the year ended December 31, 2006. Services provided by former affiliates and recharged to PacifiCorp related primarily to lease payments, captive insurance, administrative services and payroll costs and related benefits of ScottishPower employees working on international assignment in the United States. These expenses totaled \$10 million for the year ended December 31, 2006.

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NOTES TO FINANCIAL STATEMENTS (Continued)			

(16) Jointly Owned Utility Plants

Under joint plant ownership agreements with other utilities, PacifiCorp, as a tenant in common, has undivided interests in jointly owned generation and transmission plants. PacifiCorp accounts for its proportional share of each plant. Operating costs of each plant are assigned to joint owners based on ownership percentage or energy purchased, depending on the nature of the cost. Operating expenses in the Statement of Income include PacifiCorp's share of the expenses of these units.

The amounts shown in the table below represent PacifiCorp's share in each jointly owned plant at December 31, 2007 (dollars in millions):

	PacifiCorp Share	Plant in Service	Accumulated Depreciation/ Amortization	Construction Work-in- Progress
Jim Bridger Nos. 1 - 4 (a)	67%	\$ 965	\$ 505	\$ 13
Wyodak (a)	80	329	173	1
Hunter No. 1	94	304	148	1
Colstrip Nos. 3 and 4 (a)	10	243	123	1
Hunter No. 2	60	192	88	1
Hermiston (b)	50	170	38	2
Craig Nos. 1 and 2	19	167	78	1
Hayden No. 1	25	44	21	1
Foot Creek	79	37	13	-
Hayden No. 2	13	27	14	-
Other transmission and distribution plants	Various	80	24	2
Total		\$ 2,558	\$ 1,225	\$ 23

(a) Includes transmission lines and substations.

(b) Additionally, PacifiCorp has contracted to purchase the remaining 50% of the output of the Hermiston plant.

Under the joint ownership agreements, each participating utility is responsible for financing its share of construction, operating and leasing costs. PacifiCorp's portion is recorded in its applicable construction work-in-progress, operations, maintenance and tax accounts, which is consistent with wholly owned plants.

(17) Supplemental Cash Flow Information

A summary of supplemental cash flow information is presented in the following table (in millions):

	Year Ended December 31, 2007	Year Ended December 31, 2006
Income taxes paid	\$ 152	\$ 178
Interest paid, net of amounts capitalized	\$ 251	\$ 245

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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	922,963	(8,990,927)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	(1,416,499)			
3	Preceding Quarter/Year to Date Changes in Fair Value	503,402	8,990,927		(5,939,253)
4	Total (lines 2 and 3)	(913,097)	8,990,927		(5,939,253)
5	Balance of Account 219 at End of Preceding Quarter/Year	9,866			(5,939,253)
6	Balance of Account 219 at Beginning of Current Year	9,866			(5,939,253)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value	31,088			2,381,915
9	Total (lines 7 and 8)	31,088			2,381,915
10	Balance of Account 219 at End of Current Quarter/Year	40,954			(3,557,338)

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FOOTNOTE DATA			

Schedule Page: 122(a)(b) Line No.: 5 Column: b

Unrealized gain on available-for-sale securities of \$15,900 less tax of \$6,034 netting to \$9,866.

Schedule Page: 122(a)(b) Line No.: 5 Column: e

Adjustment to initially apply SFAS No. 158 (pension and other postretirement plans) of (\$9,571,706) less tax of (\$3,632,453) netting to (\$5,939,253).

Schedule Page: 122(a)(b) Line No.: 5 Column: g

Unrealized gain on cash flow hedges of \$3,299,410 less tax of \$1,252,158 netting to \$2,047,252.

For a further discussion on cash flow hedging, refer to Page 122, *Notes to the Financial Statements - Note 7 - Risk Management* of this Form No. 1.

Schedule Page: 122(a)(b) Line No.: 10 Column: b

Unrealized gain on available-for-sale securities of \$66,003 less tax of \$25,049 netting to \$40,954.

Schedule Page: 122(a)(b) Line No.: 10 Column: e

Unrecognized amounts on retirement benefits of (\$5,733,112) less tax of (\$2,175,774) netting to (\$3,557,338).

Schedule Page: 122(a)(b) Line No.: 10 Column: g

For a further discussion on cash flow hedging, refer to Page 122, *Notes to the Financial Statements - Note 7 - Risk Management* of this Form No. 1.



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SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION					
Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (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)	16,361,058,390	16,361,058,390		
4	Property Under Capital Leases	49,253,139	49,253,139		
5	Plant Purchased or Sold	21,858	21,858		
6	Completed Construction not Classified	56,258,176	56,258,176		
7	Experimental Plant Unclassified				
8	Total (3 thru 7)	16,466,591,563	16,466,591,563		
9	Leased to Others				
10	Held for Future Use	13,697,167	13,697,167		
11	Construction Work in Progress	941,818,776	941,818,776		
12	Acquisition Adjustments	157,193,780	157,193,780		
13	Total Utility Plant (8 thru 12)	17,579,301,286	17,579,301,286		
14	Accum Prov for Depr, Amort, & Depl	6,691,765,903	6,691,765,903		
15	Net Utility Plant (13 less 14)	10,887,535,383	10,887,535,383		
16	Detail of Accum Prov for Depr, Amort & Depl				
17	In Service:				
18	Depreciation	6,199,821,444	6,199,821,444		
19	Amort & Depl of Producing Nat Gas Land/Land Right				
20	Amort of Underground Storage Land/Land Rights				
21	Amort of Other Utility Plant	406,576,292	406,576,292		
22	Total In Service (18 thru 21)	6,606,397,736	6,606,397,736		
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	85,368,167	85,368,167		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	6,691,765,903	6,691,765,903		

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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
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FOOTNOTE DATA			

Schedule Page: 200 Line No.: 18 Column: c

Depreciation is comprised of:

Depreciation	\$6,168,852,765
Depletion	<u>30,968,679</u>
Total	\$6,199,821,444

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Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)				
<p>1. Report below the original cost of electric plant in service according to the prescribed accounts.</p> <p>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.</p> <p>3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.</p> <p>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.</p> <p>5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.</p> <p>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)</p>				
Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	
1	1. INTANGIBLE PLANT			
2	(301) Organization			
3	(302) Franchises and Consents	118,267,763	504,028	
4	(303) Miscellaneous Intangible Plant	559,380,026	17,245,176	
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	677,647,789	17,749,204	
6	2. PRODUCTION PLANT			
7	A. Steam Production Plant			
8	(310) Land and Land Rights	91,208,656	3,471,496	
9	(311) Structures and Improvements	779,197,667	14,484,117	
10	(312) Boiler Plant Equipment	2,781,886,567	129,704,587	
11	(313) Engines and Engine-Driven Generators			
12	(314) Turbogenerator Units	738,388,257	28,167,842	
13	(315) Accessory Electric Equipment	332,567,245	2,805,658	
14	(316) Misc. Power Plant Equipment	28,330,149	448,315	
15	(317) Asset Retirement Costs for Steam Production	30,882,673	6,468,093	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	4,782,461,214	185,550,108	
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	19,596,718	97,661	
28	(331) Structures and Improvements	82,436,894	2,336,240	
29	(332) Reservoirs, Dams, and Waterways	286,079,560	8,829,245	
30	(333) Water Wheels, Turbines, and Generators	88,024,472	4,219,560	
31	(334) Accessory Electric Equipment	41,597,094	3,071,144	
32	(335) Misc. Power Plant Equipment	2,578,674	21,526	
33	(336) Roads, Railroads, and Bridges	13,657,854	242,052	
34	(337) Asset Retirement Costs for Hydraulic Production	6,467,411		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	540,438,677	18,817,428	
36	D. Other Production Plant			
37	(340) Land and Land Rights	21,542,190	480	
38	(341) Structures and Improvements	49,582,610	245,417	
39	(342) Fuel Holders, Products, and Accessories	29,408,939		
40	(343) Prime Movers	545,929,902	585,327,485	
41	(344) Generators	125,337,407	-1,314,978	
42	(345) Accessory Electric Equipment	34,100,365	903,672	
43	(346) Misc. Power Plant Equipment	3,720,805		
44	(347) Asset Retirement Costs for Other Production	1,048,775	488,314	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	810,670,993	585,650,390	
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	6,133,570,884	790,017,926	

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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	92,439,042	985,860	
49	(352) Structures and Improvements	55,260,234	1,574,793	
50	(353) Station Equipment	963,334,561	62,435,219	
51	(354) Towers and Fixtures	381,378,303	53,145,900	
52	(355) Poles and Fixtures	511,002,983	23,556,843	
53	(356) Overhead Conductors and Devices	663,377,121	41,779,674	
54	(357) Underground Conduit	3,277,188	615	
55	(358) Underground Conductors and Devices	7,274,658	90,854	
56	(359) Roads and Trails	11,494,522		
57	(359.1) Asset Retirement Costs for Transmission Plant			
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	2,688,838,612	183,569,758	
59	4. DISTRIBUTION PLANT			
60	(360) Land and Land Rights	44,640,344	1,123,743	
61	(361) Structures and Improvements	47,082,597	689,998	
62	(362) Station Equipment	647,283,612	43,091,471	
63	(363) Storage Battery Equipment	1,457,804		
64	(364) Poles, Towers, and Fixtures	809,956,004	40,417,072	
65	(365) Overhead Conductors and Devices	590,582,713	20,493,660	
66	(366) Underground Conduit	257,642,017	12,947,842	
67	(367) Underground Conductors and Devices	611,654,574	39,123,488	
68	(368) Line Transformers	922,967,948	59,329,640	
69	(369) Services	463,770,713	40,324,721	
70	(370) Meters	189,416,286	22,360,645	
71	(371) Installations on Customer Premises	8,869,255	48,733	
72	(372) Leased Property on Customer Premises	49,658		
73	(373) Street Lighting and Signal Systems	57,030,679	2,787,534	
74	(374) Asset Retirement Costs for Distribution Plant	225,168	149,235	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	4,652,629,372	282,887,782	
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	15,030,303	291,125	
87	(390) Structures and Improvements	224,733,346	5,514,568	
88	(391) Office Furniture and Equipment	104,322,537	11,048,250	
89	(392) Transportation Equipment	96,674,943	4,156,332	
90	(393) Stores Equipment	13,140,110	290,324	
91	(394) Tools, Shop and Garage Equipment	60,763,715	2,938,399	
92	(395) Laboratory Equipment	37,567,486	3,131,390	
93	(396) Power Operated Equipment	122,178,506	15,708,612	
94	(397) Communication Equipment	232,114,066	11,461,421	
95	(398) Miscellaneous Equipment	5,387,332	417,212	
96	SUBTOTAL (Enter Total of lines 86 thru 95)	911,912,344	54,957,633	
97	(399) Other Tangible Property	252,461,068	16,774,084	
98	(399.1) Asset Retirement Costs for General Plant	42,454		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	1,164,415,866	71,731,727	
100	TOTAL (Accounts 101 and 106)	15,317,102,523	1,345,956,397	
101	(102) Electric Plant Purchased (See Instr. 8)			
102	(Less) (102) Electric Plant Sold (See Instr. 8)		-21,858	
103	(103) Experimental Plant Unclassified			
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	15,317,102,523	1,345,978,255	

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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
105,143		-4,734,194	88,585,565		48
103,867		7,013,837	63,744,997		49
3,546,741		7,047,446	1,029,270,485		50
56,015			434,468,188		51
1,819,572			532,740,254		52
1,422,654		510	703,734,651		53
191			3,277,612		54
			7,365,512		55
22,295			11,472,227		56
					57
7,076,478		9,327,599	2,874,659,491		58
					59
167,287		78,642	45,675,442		60
194,742		3,778,133	51,355,986		61
2,791,938		-3,657,786	683,925,359		62
			1,457,804		63
6,347,355			844,025,721		64
3,334,650		-510	607,741,213		65
572,523		-5,031	270,012,305		66
1,268,204			649,509,858		67
8,279,043		-14,087	974,004,458		68
722,101			503,373,333		69
26,835,453			184,941,478		70
57,384			8,860,604		71
			49,658		72
488,514			59,329,699		73
			374,403		74
51,059,194		179,361	4,884,637,321		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
37,486			15,283,942		86
3,452,512		28,748	226,824,150		87
19,080,807		-44,307	96,245,673		88
4,626,589		-808,794	95,395,892		89
71,854		94,696	13,453,276		90
1,206,651		46,250	62,541,713		91
737,004		225,311	40,187,183		92
15,860,420		264,183	122,290,881		93
5,249,729		2,747,310	241,073,068		94
120,230		246,580	5,930,894		95
50,443,282		2,799,977	919,226,672		96
6,078,187	-56,063	-100,771	263,000,141		97
	-2,706		39,748		98
56,521,469	-58,769	2,699,206	1,182,266,561		99
229,505,751	-16,213,678	-22,925	16,417,316,566		100
					101
			-21,858		102
					103
229,505,751	-16,213,678	-22,925	16,417,338,424		104

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
PacifiCorp			
FOOTNOTE DATA			

Schedule Page: 204 Line No.: 97 Column: b

Account	Description (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
39921	LAND OWNED IN FEE	\$2,634,916	\$ -	\$ -	\$ -	\$ -	\$2,634,916
39922	LAND RIGHTS	52,472,247	78,400	-	-	-	52,550,647
39930	STRUCTURES	37,328,227	2,341,876	69,266	-	-	39,600,831
39941	SURFACE - PLANT EQUIPMENT	11,794,358	88,256	-	-	-	11,882,614
39944	SURFACE - ELECTRIC POWER FACILITIES	3,181,747	242,828	-	-	-	3,424,575
39945	UNDERGROUND - COAL MINE EQUIPMENT	55,358,227	7,780,011	4,172,096	-	-	58,966,142
39946	LONGWALL SHIELDS	17,699,562	-	-	-	-	17,699,562
39947	LONGWALL EQUIPMENT	10,786,602	-	-	-	-	10,786,602
39948	MAINLINE EXTENSION	15,253,657	2,593,869	1,319,064	-	-	16,528,462
39949	SECTION EXTENSION	3,290,467	645,388	-	-	-	3,935,855
39951	VEHICLES	1,098,151	183,720	201,724	-	35,820	1,115,967
39952	HEAVY CONSTRUCTION EQUIPMENT	3,486,584	1,584,054	91,822	-	(136,591)	4,842,225
39960	MISCELLANEOUS GENERAL EQUIPMENT	2,114,401	336,436	217,418	-	-	2,233,419
39961	COMPUTERS - MAINFRAME	600,464	56,797	6,797	-	-	650,464
39970	MINE DEVELOPMENT AND ROAD EXTENSION	34,700,270	842,459	-	-	-	35,542,729
399915	Coal Mine ARO	661,188	-	-	(56,063)	-	605,125
	TOTAL PLANT USED IN MINING ACTIVITIES	\$252,461,068	\$16,774,094	\$6,078,187	\$(56,063)	\$(100,771)	\$263,000,141

Schedule Page: 204 Line No.: 97 Column: c

See footnote line 97, column b.

Schedule Page: 204 Line No.: 97 Column: d

See footnote line 97, column b.

Schedule Page: 204 Line No.: 97 Column: e

See footnote line 97, column b.

Schedule Page: 204 Line No.: 97 Column: f

See footnote line 97, column b.

Schedule Page: 204 Line No.: 97 Column: g

See footnote line 97, column b.

Schedule Page: 204 Line No.: 102 Column: c

Refer to pages 108-109 Important Changes During the Year.



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(Next Page is 214)

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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					
3	Oquirrh Substation	2005	2009	2,245,898	
4	North Horn Mountain Coal Properties	1977	2010-2018	953,014	
5	Barnes Butte Substation	2007	2009	746,268	
6	White Rock Substation	2007	2009	505,024	
7	Wild Horse Wind Plant	2007	2010	6,863,094	
8	Twelve Mile Wind Plant	2007	2010	2,058,839	
9					
10	Miscellaneous, each under \$250,000			325,030	
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	Other Property:				
22					
23					
24					
25					
26					
27	Miscellaneous, each under \$250,000:				
28					
29					
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33					
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42					
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45					
46					
47	Total			13,697,167	

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
PacifiCorp			
FOOTNOTE DATA			

Schedule Page: 214 Line No.: 4 Column: c

The North Horn Mountain Coal Properties are needed to access future coal portals and federal coal reserves when existing East Mountain coal mines are mined out.

Schedule Page: 214 Line No.: 10 Column: c

Various dates and plans.

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/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	Intangible:			
2	Klamath Relicensing			48,278,400
3	Yale Relicensing (Lewis River)			13,540,949
4	Merwin Relicensing (Lewis River)			10,384,818
5	Swift Relicensing (Lewis River)			9,847,042
6	Prospect 1, 2 & 4 Relicensing (Rogue River)			6,564,429
7				
8	Production:			
9	Goodhoe Hills Wind Plant			168,750,742
10	Cholla Unit #4 -CAI Environmental Projects			115,431,568
11	Marengo II Wind Plant			96,048,595
12	Seven Mile Hill Wind Plant			57,553,129
13	Glenrock Wind Plant			57,099,009
14	Rolling Hills Wind Plant			55,573,522
15	North Umpqua Relicensing Implementation			14,767,436
16	Huntington Water Efficiency Management			10,248,167
17	Copco 2 Electrical Overhaul			7,369,007
18	Lewis River Relicensing Implementation			7,339,997
19	Dave Johnston Unit #4 - Boiler/Turbine Controls			4,815,791
20	Cutler #2 Runner			3,994,977
21	Cholla - Coal Unloading & Handling			2,323,444
22	Cholla - 135 Car Rail Siding			1,712,449
23	Hermiston Purchase 1st & 2nd Stage Buckets			1,464,829
24	Cholla Unit #4 - Exciter & AVR Replacement			1,446,087
25	Cholla Unit #4 - Economizer Replacement			1,175,317
26	Hydro Facilities Fall Protection			1,052,808
27	Carbon - Fly Ash Handling System			1,040,822
28				
29	Transmission:			
30	Three Mile Knoll - New 345-138kV Substation			19,266,598
31	Line 1 Convert to 115kV, Line 14 Cap Relief			11,745,674
32	Populus-Terminal: Dbl Ckt 345 kV Transmission Line			11,262,090
33	Herriman Purch Sub Prop & Trans ROW			3,400,216
34	Craner Flat Substation - Install 138 kV			2,802,868
35	Copco 2 Install 230/115 Transformer & Breaker			2,771,271
36	Path 18 Reliability Improvements			2,436,329
37	Transmission Relay Replacement Zone 3 Setting			1,903,622
38	Mona-Oquirrh Line			1,714,504
39	Yakima Transmission ROW Renewal Project			1,424,987
40	Shute Creek to Mona System Upgrade			1,338,071
41	Copco II Sub Repl Exist 115-69kV Transformer			1,205,268
42	Line 37 Conv to 115kV Bld Nickel Mt Substation			1,072,946
43	TOTAL			941,818,776

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/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	Upper Green River Basin -			
2	Jonah Field & Paradise Subs/Lines	1,069,167		
3				
4	Distribution:			
5	Yew Avenue - Constuct New Substation (Tetherow)	5,953,979		
6	Elk Horn Install 115-12.5kV Two Fdr Substation	5,527,744		
7	Wasatch Front Automated Meter Reading	4,154,846		
8	Cozydale Build New 138-12.5kV Substation	3,714,847		
9	Pleasant Grove Sub Conv to 138kV	2,979,550		
10	Campbell Sub Increase Capacity	2,938,656		
11	Cedar Indust Pk New 138-12.5kV Substation Site	1,304,077		
12	Jumbers Point New 138-12.5kV Substation Site	1,170,198		
13				
14	General:			
15	Mobile Radio Replacement Project	6,946,084		
16	IVRAAR Agent Access Rtr	3,402,849		
17	IP Telephony Project	1,770,745		
18	Jim Bridger - Replacement RAS A&B Scheme Project	1,646,766		
19	Deer Creek -Roof Bolter	1,158,181		
20				
21	Miscellaneous Projects each under \$1,000,000	137,913,309		
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
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36				
37				
38				
39				
40				
41				
42				
43	TOTAL	941,818,776		

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 216.1 Line No.: 21 Column: a

A \$1,000,000 reporting threshold was approved for PacifiCorp effective with the 1993 reporting year by the Chief Accountant, Federal Regulatory Commission in a letter to the company dated August 5, 1993, Docket No. AC93-181-000.

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(Next Page is 219)

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)					
<p>1. Explain in a footnote any important adjustments during year.</p> <p>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.</p> <p>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.</p> <p>4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.</p>					
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	5,945,570,482	5,945,570,482		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	418,496,844	418,496,844		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	30,857,380	30,857,380		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	449,354,224	449,354,224		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	200,410,311	200,410,311		
13	Cost of Removal	44,136,308	44,136,308		
14	Salvage (Credit)	9,429,174	9,429,174		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	235,117,445	235,117,445		
16	Other Debit or Cr. Items (Describe, details in footnote):	40,014,183	40,014,183		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	6,199,821,444	6,199,821,444		
Section B. Balances at End of Year According to Functional Classification					
20	Steam Production	2,469,739,015	2,469,739,015		
21	Nuclear Production				
22	Hydraulic Production-Conventional	231,109,912	231,109,912		
23	Hydraulic Production-Pumped Storage				
24	Other Production	105,487,036	105,487,036		
25	Transmission	1,077,851,432	1,077,851,432		
26	Distribution	1,844,588,160	1,844,588,160		
27	Regional Transmission and Market Operation				
28	General	471,045,889	471,045,889		
29	TOTAL (Enter Total of lines 20 thru 28)	6,199,821,444	6,199,821,444		

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 219 Line No.: 4 Column: b

PacifiCorp records the depreciation expense of asset retirement obligations as either a regulatory asset or (liability).

Schedule Page: 219 Line No.: 8 Column: b

Depreciation of mining assets included in account 151 Fuel Stock	\$ 13,939,854
Account 143.3 Joint Owner Receivable - Depreciation expense billed to Joint Owners	266,558
Account 182.3 Other Regulatory Assets	2,505,420
Vehicle Depreciation allocated to O&M based on usage activity	12,494,116
Account 503.1 Blundell Depletion	640,038
Account 503 IGC Depreciation and Amortization	1,011,394
Total Other Accounts	\$ 30,857,380

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

Other items including:	\$ 40,014,183
-Recovery from third parties for asset relocations and damaged property	
-Insurance recoveries	
-Adjustments of reserve related to electric plant sold	
-Reclassifications from electric plant	

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)					
<p>1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.</p> <p>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)</p> <p>(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.</p> <p>(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.</p> <p>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.</p>					
Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)	
1	PACIFIC MINERALS, INC	12/31/1991			
2	Common Stock			1	
3	Capital Contributions			14,160,000	
4	Undistributed Earnings			86,602,065	
5	SUBTOTAL			100,762,066	
6					
7	PACIFICORP ENVIRONMENTAL REMEDIATION COMPANY	8/19/1994			
8	Common Stock			900,000	
9	Capital Contributions			5,608,526	
10	Acquisition of Minority Interest				
11	Undistributed Subsidiary Earnings			5,851,021	
12	SUBTOTAL			12,359,547	
13					
14	PACIFIC FUTURE GENERATIONS, INC	9/19/1999			
15	Undistributed Subsidiary Earnings			-9,627	
16	SUBTOTAL			-9,627	
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42	Total Cost of Account 123.1 \$	48,036,514		TOTAL	113,111,986

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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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 from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		1		2
		32,460,000		3
6,808,914		93,410,979		4
6,808,914		125,870,980		5
				6
				7
		900,000		8
		13,719,625		9
		956,888		10
1,716,475		7,567,496		11
1,716,475		23,144,009		12
				13
				14
-325		-9,952		15
-325		-9,952		16
				17
				18
				19
				20
				21
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				23
				24
				25
				26
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				39
				40
				41
8,525,064		149,005,037		42

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
PacifiCorp			
FOOTNOTE DATA			

Schedule Page: 224 Line No.: 3 Column: g

Reflects \$18,300,000 capital contribution from parent company in 2007.

Schedule Page: 224 Line No.: 4 Column: e

Equity earnings from Pacific Minerals, Inc. (PMI) consist of inter-company profit on coal to PacifiCorp from Bridger Coal Company, that PMI jointly owns with Idaho Power Company, and are not recorded in account 418.1, Equity in Earnings of Subsidiary Companies. PacifiCorp records PMI's earnings before interest and taxes as an offset to fuel expense, and records interest and taxes to their respective line items.

Schedule Page: 224 Line No.: 9 Column: g

Reflects \$8,111,099 of deferred tax assets assumed from parent company in 2007.

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(Next Page is 227)

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
MATERIALS AND SUPPLIES					
<p>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.</p> <p>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.</p>					
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)	82,230,862	98,334,182	Electric	
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)	48,572,876	53,387,313	Electric	
6	Assigned to - Operations and Maintenance				
7	Production Plant (Estimated)	64,636,918	74,067,221	Electric	
8	Transmission Plant (Estimated)	4,250,120	6,228,512	Electric	
9	Distribution Plant (Estimated)	8,330,981	11,906,581	Electric	
10	Regional Transmission and Market Operation Plant (Estimated)				
11	Assigned to - Other (provide details in footnote)	3,940,971	4,460,395	Electric	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	129,731,866	150,050,022		
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)	211,962,728	248,384,204		

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

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

Mining M&S	\$3,408,500
General Plant M&S	<u>532,471</u>
	\$3,940,971

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

Mining M&S	\$4,314,408
General Plant M&S	<u>145,987</u>
	\$4,460,395

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
Allowances (Accounts 158.1 and 158.2)					
<p>1. Report below the particulars (details) called for concerning allowances.</p> <p>2. Report all acquisitions of allowances at cost.</p> <p>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.</p> <p>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).</p> <p>5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.</p>					
Line No.	Allowances Inventory (Account 158.1) (a)	Current Year		2008	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	130,083.00		113,095.00	
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	90,814.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Saracen Energy	7,800.00			
23	Louis Dreyfus	5,000.00			
24	Alpha Energy	7,500.00			
25	Fortis Energy	2,500.00			
26	Dte Coal Services	2,500.00			
27					
28	Total	25,300.00			
29	Balance-End of Year	13,969.00		113,095.00	
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	2,259.00		2,259.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	2,259.00			
40	Balance-End of Year			2,259.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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Allowances (Accounts 158.1 and 158.2) (Continued)

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

2009		2010		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
121,095.00		144,002.00		4,035,432.00		4,543,707.00		1
								2
								3
				156,643.00		156,643.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
						90,814.00		17
								18
								19
								20
								21
						7,800.00		22
						5,000.00		23
						7,500.00		24
						2,500.00		25
						2,500.00		26
								27
						25,300.00		28
121,095.00		144,002.00		4,192,075.00		4,584,236.00		29
								30
								31
								32
								33
								34
								35
2,259.00		2,259.00		110,921.00		119,957.00		36
				4,528.00		4,528.00		37
								38
				2,269.00		4,528.00		39
2,259.00		2,259.00		113,180.00		119,957.00		40
								41
								42
								43
								44
								45
								46

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008		Year/Period of Report End of 2007/Q4	
UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)							
Line No.	Description of Unrecovered Plant and Regulatory Study Costs (Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)) (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)	
				Account Charged (d)	Amount (e)		
21	Unrecovered Plant: Trojan Nuclear	6,839,022	17,402	407	1,672,435	5,149,185	
22	Plant located near Portland, OR						
23	Date of Retirement: 12/31/1992						
24	Date of Commission Authorization:						
25	04/20/1993						
26	Amortization Period: 01/1993						
27	through 01/2011						
28							
29	Unrecovered Plant: Powerdale						
30	Hydro Electric Plant		11,220,011	407	780,127	10,439,884	
31	Date of Retirement: 02/08/2007						
32	Date of Commission Authorization:						
33	05/14/2007						
34	Amortization Period: 05/2007						
35	through 12/2010						
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							
49	TOTAL	6,839,022	11,202,609		2,452,562	15,589,069	

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

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

Represents the sale of a portion of the Trojan plant switchyard assets.

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	Transmission Studies				
2	Aref 235776, 256959, 346975	39	561.6	39	456.2
3	Aref 314945	53,813	561.6	59,909	456.2
4	Aref 367339	3,137	561.6	3,137	456.2
5	Aref 401968	666	561.6	666	456.2
6	Aref 404233	471	561.6	471	456.2
7	Aref 404235	471	561.6	471	456.2
8	Aref 412890, 413567, 413571	461	561.6	461	456.2
9	Aref 412893	358	561.6	358	456.2
10	See Footnote	422	561.6	422	456.2
11	Aref 412911	10	561.6	10	456.2
12	Aref 412919	525	561.6	525	456.2
13	Aref 413576, 413580	10	561.6	10	456.2
14	Aref 415091	510	561.6	510	456.2
15	See Footnote	1,151	561.6	1,151	456.2
16	See Footnote	852	561.6	268	456.2
17	Aref 417614, 417702	8	561.6	8	456.2
18	Aref 421625, 421626	439	561.6	439	456.2
19	Aref 417581	439	561.6	439	456.2
20	Aref 421623, 421624	439	561.6	439	456.2
21	Generation Studies				
22	GIQ0053	(1,299)	561.7	(1,299)	456.2
23	GIQ0060	1,286	561.7	1,286	456.2
24	GIQ0063, GIQ0064	428	561.7	428	456.2
25	GIQ0071	(169)	561.7	(169)	456.2
26	GIQ0074	1,252	561.7	1,252	456.2
27	See Footnote	3,334	561.7	3,730	456.2
28	GIQ0081		561.7	88	456.2
29	GIQ0091	2,223	561.7	5,597	456.2
30	GIQ0063, GIQ0064	1,661	561.7	21,884	456.2
31	GIQ0090	16,531	561.7	16,584	456.2
32	GIQ0059	47,651	561.7	57,356	456.2
33	GIQ0060	4,466	561.7	19,417	456.2
34	GIQ0080	16,054	561.7	16,464	456.2
35	GIQ0093	2,181	561.7	2,586	456.2
36	GIQ0071	332	561.7	636	456.2
37	GIQ0092	1,956	561.7	2,376	456.2
38	GIQ0094	8,142	561.7	8,195	456.2
39	GIQ0095	26,011	561.7	26,064	456.2
40	GIQ0098	(1,584)	561.7	(1,260)	456.2

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Transmission Service and Generation Interconnection Study Costs (continued)					
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	Aref 421599	439	561.6	439	456.2
3	Aref 421621, 421622	439	561.6	439	456.2
4	Aref 421615, 421616, 421617	439	561.6	439	456.2
5	Aref 417622	459	561.6	459	456.2
6	Aref 421618, 421619, 421620	439	561.6	439	456.2
7	See Footnote	482	561.6	482	456.2
8	Aref 424584, 424583	482	561.6	482	456.2
9	Aref 424140, 424146	121	561.6	121	456.2
10	Aref 427103, 427104, 427105	82	561.6	82	456.2
11	Aref 428908, 428909, 428910	82	561.6	82	456.2
12	See Footnote	86	561.6	86	456.2
13	Aref 412893, 412908	20	561.6	20	456.2
14	See Footnote	680	561.6	680	456.2
15	Aref 421618, 421619, 421620	19	561.6	19	456.2
16	IRP	4,450	561.6		
17	Aref 291675, 292491, 292494	73,869	561.6		
18	Aref 317351	113,745	561.6		
19	Aref 301557	91,721	561.6		
20	Aref 306176	110,797	561.6		
21	Generation Studies				
22	GIQ0096	40,643	561.7	40,696	456.2
23	GIQ0097	3,458	561.7	3,530	456.2
24	GIQ0099	3,093	561.7	4,894	456.2
25	GIQ0100	7,204	561.7	7,755	456.2
26	GIQ0101	4,659	561.7	5,116	456.2
27	GIQ0089	22,521	561.7	22,826	456.2
28	GIQ0102	2,943	561.7	3,694	456.2
29	GIQ0073	22,110	561.7	25,201	456.2
30	GIQ0108	2,415	561.7	2,486	456.2
31	GIQ0109	2,131	561.7	2,184	456.2
32	GIQ0110	6,070	561.7	6,158	456.2
33	GIQ0071	37,343	561.7	37,413	456.2
34	GIQ0115	8,673	561.7	8,673	456.2
35	GIQ0111	1,763	561.7	1,851	456.2
36	GIQ0116	500	561.7	500	456.2
37	GIQ0112	26,771	561.7	26,874	456.2
38	GIQ0113	4,512	561.7	4,512	456.2
39	GIQ0114	62	561.7	62	456.2
40	GIQ0119	7,457	561.7	7,457	456.2

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
Transmission Service and Generation Interconnection Study Costs (continued)					
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	Aref 345779	22,398	561.6		
3	Aref 371619	412	561.6		
4	Aref 374355	721	561.6		
5	Aref 378464	105	561.6		
6	Aref 381927	9,484	561.6		
7	Aref 379612	10,278	561.6		
8	Aref 384328	5,664	561.6		
9	Aref 384190	5,355	561.6		
10	Aref 384329	5,434	561.6		
11	TCA	1,648	561.6		
12	Aref 393373	2,605	561.6		
13	Aref 396655	6,491	561.6		
14	Aref 381927	2,299	561.6		
15	Aref 384190	2,584	561.6		
16	Aref 384328	2,249	561.6		
17	Aref 384329	5,523	561.6		
18	Aref 412872	1,098	561.6		
19	Aref 414741	488	561.6		
20	Aref 384190	536	561.6		
21	Generation Studies				
22	GIQ0117	24,566	561.7	24,566	456.2
23	GIQ0120	3,681	561.7	3,681	456.2
24	GIQ0090	50,825	561.7	50,825	456.2
25	GIQ0121	3,614	561.7	3,614	456.2
26	GIQ0092	4,556	561.7	4,556	456.2
27	GIQ0080	14,801	561.7	14,801	456.2
28	GIQ0097	13,624	561.7	13,624	456.2
29	GIQ0127	3,387	561.7	3,387	456.2
30	GIQ0128	6,661	561.7	6,661	456.2
31	GIQ0089	15,210	561.7	15,210	456.2
32	GIQ0099	7,634	561.7	7,634	456.2
33	GIQ0129	5,798	561.7	5,798	456.2
34	GIQ0060	18,695	561.7	18,695	456.2
35	GIQ0100	45,344	561.7	45,344	456.2
36	GIQ0130	2,862	561.7	2,862	456.2
37	GIQ0082	16,002	561.7	16,002	456.2
38	GIQ0102	22,401	561.7	22,401	456.2
39	GIQ0101	3,552	561.7	3,552	456.2
40	GIQ0096	13,747	561.7	13,747	456.2

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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Transmission Service and Generation Interconnection Study Costs (continued)

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	Aref 384328	676	561.6		
3	Aref 428071	268	561.6		
4	Aref 428070	268	561.6		
5	Aref 416445	680	561.6		
6	Aref 345778	26,598	561.6		
7	Aref 363667	1,217	561.6		
8	Aref 368231	16,544	561.6		
9	Customer Studies Accruals	(451)	561.6		
10	Aref 313369	49,092	107		
11	Aref 301356, 301357	57,420	107		
12	Aref 394342	814	107		
13	Aref 394947	644	107		
14	Aref 394952	2,682	107		
15	Aref 400067	132	107		
16	Aref 400817	59	107		
17	Aref 402411	2,356	107		
18	Aref 422102	337	107		
19	Aref 425384	70	107		
20	Aref 416445	20	107		
21	Generation Studies				
22	GIQ0095	20,357	561.7	20,357	456.2
23	GIQ0132	22,355	561.7	22,355	456.2
24	GIQ0134	22,715	561.7	22,715	456.2
25	GIQ0135	4,819	561.7	4,819	456.2
26	GIQ0138	5,476	561.7	5,476	456.2
27	GIQ0139	11,323	561.7	11,323	456.2
28	GIQ0140	948	561.7	948	456.2
29	GIQ0141	5,368	561.7	5,368	456.2
30	GIQ0119	20,747	561.7	20,747	456.2
31	GIQ0142	2,961	561.7	2,961	456.2
32	GIQ0143	1,158	561.7	1,158	456.2
33	GIQ0144	5,879	561.7	5,879	456.2
34	GIQ0149	913	561.7	913	456.2
35	GIQ0151	4,087	561.7	4,087	456.2
36	GIQ0145	3,517	561.7	3,517	456.2
37	GIQ0148	6,343	561.7	6,343	456.2
38	GIQ0149	2,034	561.7	2,034	456.2
39	GIQ0136	1,556	561.7	1,556	456.2
40	GIQ0137	1,394	561.7	1,394	456.2

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
Transmission Service and Generation Interconnection Study Costs (continued)					
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	Aref 432138	80	107		
3	Aref 432141	80	107		
4	Aref 432805	2,080	107		
5	Aref 434090	20	107		
6	Aref 442184	20	107		
7	Aref 444572	20	107		
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	Generation Studies				
22	GIQ0152	1,938	561.7	1,938	456.2
23	GIQ0153	2,391	561.7	2,391	456.2
24	GIQ0154	2,747	561.7	2,747	456.2
25	GIQ0155	2,684	561.7	2,684	456.2
26	GIQ0117	14,122	561.7	14,122	456.2
27	GIQ0128	7,358	561.7	7,358	456.2
28	See Footnote	14,827	561.7	14,827	456.2
29	GIQ0161	1,388	561.7	1,388	456.2
30	GIQ0100	22,439	561.7	22,439	456.2
31	GIQ0129	8,474	561.7	8,474	456.2
32	GIQ0162	965	561.7	965	456.2
33	GIQ0163	304	561.7	304	456.2
34	GIQ0164	554	561.7	554	456.2
35	GIQ0165	618	561.7	618	456.2
36	GIQ0112	6,176	561.7	6,176	456.2
37	GIQ0139	7,540	561.7	7,540	456.2
38	GIQ0166	1,462	561.7	1,462	456.2
39	GIQ0167	992	561.7	992	456.2
40	GIQ0168	394	561.7	394	456.2

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
Transmission Service and Generation Interconnection Study Costs (continued)					
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	GIQ0141	4,745	561.7	4,745	456.2
23	GIQ0093	264	561.7	264	456.2
24	GIQ0132	1,426	561.7	1,426	456.2
25	GIQ0169	127	561.7	127	456.2
26	GIQ0170	127	561.7	127	456.2
27	GIQ0171	395	561.7	395	456.2
28	GIQ0119	942	561.7	942	456.2
29	GIQ0172	590	561.7	590	456.2
30	GIQ0173	127	561.7	127	456.2
31	GIQ0138	165	561.7	165	456.2
32	GIQ0174	273	561.7	273	456.2
33	GIQ0175	75	561.7	75	456.2
34	GIQ0130	155	561.7	155	456.2
35	GIQ0135	409	561.7	409	456.2
36	GIQ0136	285	561.7	285	456.2
37	GIQ0137	285	561.7	285	456.2
38	Customer Studies Accruals	5,805	561.7	5,805	456.2
39	Aref 316762	608	561.7		
40	Aref 316764	152	561.7		

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
Transmission Service and Generation Interconnection Study Costs (continued)					
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	Aref 316762	4,036	561.7		
23	Aref 316260	647	561.7		
24	Aref 316764	7,631	561.7		
25	GIQ0107	4,712	561.7		
26	GIQ0075	607	561.7		
27	GIQ0122	19,375	561.7		
28	GIQ0123	3,936	561.7		
29	GIQ0124	5,189	561.7		
30	GIQ0125	13,254	561.7		
31	GIQ0126	19,409	561.7		
32	GIQ0131	721	561.7		
33	GIQ0122	3,509	561.7		
34	GIQ0131	5,651	561.7		
35	Aref 431343	46	107		
36	Aref 431345	46	107		
37	Aref 431347	46	107		
38	Aref 431348	46	107		
39	Aref 431350	112	107		
40	GIQ0126	2,931	107		

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 231 Line No.: 10 Column: a

Transmission Studies: Aref 412896, 412899, 412890, 412905, 412908

Schedule Page: 231 Line No.: 15 Column: a

Transmission Studies: Aref 417712, 417714, 417716, 417718

Schedule Page: 231 Line No.: 16 Column: a

Transmission Studies: Aref 417471, 417474, 417476, 417478, 417480

Schedule Page: 231 Line No.: 27 Column: a

Labor, equipment and administration fees associated with hydro project in Idaho Falls, Idaho.

Schedule Page: 231.1 Line No.: 7 Column: a

Transmission Studies: Aref 424565, 424568, 424571, 424573, 424576

Schedule Page: 231.1 Line No.: 12 Column: a

Transmission Studies: Aref 412890, 412896, 412899, 412902, 412905, 413567, 413571, 413576, 413580, 412911

Schedule Page: 231.1 Line No.: 14 Column: a

Transmission Studies: Aref 417471, 417474, 417476, 417478, 417480

Schedule Page: 231.4 Line No.: 28 Column: a

Generation Studies: GIQ0102, GIQ0103, GIQ0104, GIQ0105, GIQ0106

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$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		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	California DSM Regulatory Asset	(221,524)	215,472	908	242,935	-248,987
2	Idaho DSM Regulatory Asset	5,255,937	2,131,643	908	3,135,822	4,251,758
3	Utah DSM Regulatory Asset	692,991	25,599,944	431,908	26,693,091	-400,156
4	Washington DSM Regulatory Asset	(1,791,744)	5,388,987	431,908	4,692,918	-1,095,675
5	Wyoming DSM Regulatory Asset (10)	329,053	26,226	908	72,652	282,627
6	DSM Regulatory Assets- Accruals	2,763,541	921,915			3,685,456
7	Calif. Alternative Rate For Energy (CARE)	1,389,730	1,677,761	142	1,325,266	1,742,225
8	Transition Plan - OR (10)	13,946,471		930.2	3,892,299	10,054,172
9	FAS 109 Deferred Income Taxes Electric	464,097,282		282	5,551,771	458,545,491
10	SB 1149 Implementation Costs OR Retail Access (5)	11,558,265	1,811,584	407.3	8,876,169	4,493,680
11	Energy Trust of Oregon SB1149	1,111		143	1,111	
12	Retail Access Project Inc. (Various)	1,156,535	251,523		1,408,058	
13	IDAI Costs No. CA Direct Access (5)	638,451		407.3	333,105	305,346
14	Sch 781 Direct Access Shopping Incentive	899,258	553,926	407.3	932,713	520,471
15	98 Early Retirement OR (4)	3,676,946		930.2	3,676,946	
16	Glenrock Mine Excluding Reclamation UT (9)	3,731,222		930.2	1,302,399	2,428,823
17	Deferred Excess Net Power Costs - OR UE116	137,716	12,091			149,807
18	Deferred Excess Net Power Costs - WY (1)	2,554,006	123,534	555	1,796,921	880,619
19	Deferred Excess Net Power Costs - CA		758,296			758,296
20	Deferred Excess Net Power Costs - WY 2007		29,108,115			29,108,115
21	OR SB 408 Recovery (1)	2,305,390	108,668		2,201,005	213,053
22	Environmental Costs (10)	6,045,016	2,141,798	925	1,131,270	7,055,544
23	Environmental Costs - WA (10)	(353,215)	58,507	925	158,983	-453,691
24	Reg Asset - Environmental Costs	8,080,491	1,230,366	253	7,748,899	1,561,958
25	Cholla Plant Transaction Costs (26)	11,878,997		557	1,122,425	10,756,572
26	Cholla Plant Transaction Costs - OR (26)	(569,522)	53,813			-515,709
27	Cholla Plant Transaction Costs - WA (26)	(1,026,649)	97,006			-929,643
28	Cholla Plant Transaction Costs - ID (26)	(348,968)	32,973			-315,995
29	Washington Colstrip #3 (22)	735,011		456	52,188	682,823
30	FAS 133 Derivative Net Regulatory Asset	229,837,168	26,186,602			256,023,770
31	FAS 87/88 Pension UT (7)	3,159,014		930.2	3,159,014	
32	Asset Retirement Obligations Regulatory Difference	54,860,930	20,236,504	230	22,244,031	52,853,403
33	FAS 158 Pension/Other Post Ret./SERP	565,929,191	12,384,148		352,060,406	226,252,933
34	RTO Grid West N/R Reg Asset	1,131,721				1,131,721
35	Contra Reg Asset - RTO Grid West	(1,131,721)				-1,131,721
36	RTO Grid West N/R - OR	810,234	68,645			878,879
37	RTO Grid West N/R - WY	414,098				414,098
38	RTO Grid West N/R - ID (5)	135,811		904	27,162	108,649
39	Deferred UT Independent Evaluator Fee		300,511			300,511
40	Deferred Intervenor Funding Grants (1)	861,532	286,929	928.2	555,488	592,973
41	2006 Transition Plan - WA (3)		1,982,160	920	358,438	1,623,722
42	BPA Washington Balancing Account		1,942,285			1,942,285
43	BPA Oregon Balancing Account		292,678			292,678
44	TOTAL	1,395,660,386	140,832,888		454,753,485	1,081,739,789

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$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		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	BPA Idaho Balancing Account		1,335,440			1,335,440
2	2006 Transition Plan - ID (3)		1,830,583			1,830,583
3	OR RCAC		1,633,653			1,633,653
4	Regulatory Assets - Reclass	2,090,630	48,602			2,139,232
5						
6						
7						
8						
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30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	1,395,660,386	140,832,888		454,753,485	1,081,739,789

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 232 Line No.: 12 Column: d

Account 182.3

Account 407.3

Schedule Page: 232 Line No.: 21 Column: d

Account 440

Account 442

Account 444

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

Account 228

Various Labor Accounts

Schedule Page: 232.1 Line No.: 4 Column: f

The following is a reconciliation of the regulatory asset reclassification account:

	YTD
	<u>December 31, 2007</u>
Reclassified from Regulatory Assets to Regulatory Liabilities:	
California DSM Regulatory Asset	\$ 248,987
Washington DSM Regulatory Asset	1,095,675
Utah DSM Regulatory Asset	400,156
Reclassified from Regulatory Liabilities to Regulatory Assets:	
Washington Low Income Program	41,964
Regulatory Liability Oregon Consolidated	<u>352,450</u>
	\$ 2,139,232

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(Next Page is 233)

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008		Year/Period of Report End of 2007/Q4	
MISCELLANEOUS DEFERRED DEBITS (Account 186)							
1. Report below the particulars (details) called for concerning miscellaneous deferred debits. 2. For any deferred debit being amortized, show period of amortization in column (a) 3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than \$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		Balance at End of Year (f)	
				Account Charged (d)	Amount (e)		
1	Joseph Settlement (20)	1,522,637		557	137,381	1,385,256	
2							
3	Lacomb Irrigation (24)	689,610		557	45,720	643,890	
4							
5	Facilities and Properties	303,968	118,018		403,672	18,314	
6							
7	Bogus Creek (42)	1,365,680		557	41,280	1,324,400	
8							
9	Mead Phoenix Availability						
10	& Trans Charge (50)	15,267,800		565	377,760	14,890,040	
11							
12	Lakeview Buyout (21)	90,166		557	43,280	46,886	
13							
14	TGS Buyout (23)	202,445		557	15,473	186,972	
15							
16	Hermiston Swap (35)	5,170,905		557	263,341	4,907,564	
17							
18	Deferred Longwall Costs	1,768,552	1,408,523	151	2,604,436	572,639	
19							
20	Other Deferred Debits with						
21	Amounts less than \$50,000	313,360	30,022	151	320,302	23,080	
22							
23	Point to Point Transmission	559,001	627,899		288,643	898,257	
24							
25	Deferred Costs Wyodak						
26	Settlement (22)	5,362,909		151	335,182	5,027,727	
27							
28	Jim Boyd Hydro Buyout (11)	586,925		557	82,860	504,065	
29							
30	Deferred Shelf Registration	283,538	247,227	181	434,363	96,402	
31							
32	Credit Agmt Costs (5)	2,213,533	643,094	431	456,681	2,399,946	
33							
34	PCRB LOC/SBBPA Cost (5)	1,250,875	211,607	427	324,681	1,137,801	
35							
36	Unamortized PCRB Mode Conv Cost	646,084		427	128,040	518,044	
37							
38	Emission Reduction Credits	406,980				406,980	
39							
40	Non-Current Fed/State Inc Tax	12,741,862	10,729,648		23,471,510		
41							
42	LGIA LT Transmission Prepaid	6,898,901	8,108,863		2,704,260	12,303,504	
43							
44	WA Environmental Cost-Utah Mtls	290,803		182.3	290,803		
45							
46	Financing Costs Deferred	11,187	2,028,126		2,037,946	1,367	
47	Misc. Work in Progress						
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)						
49	TOTAL	57,976,248				52,116,892	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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MISCELLANEOUS DEFERRED DEBITS (Account 186)

- Report below the particulars (details) called for concerning miscellaneous deferred debits.
- For any deferred debit being amortized, show period of amortization in column (a)
- Minor item (1% of the Balance at End of Year for Account 186 or amounts less than \$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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1						
2	Property Damage Repairs	28,527	122,398		150,891	34
3						
4	Lease Incentives (11)		1,371,847	454.1	33,616	1,338,231
5						
6	LT Lease Comm Prepaid (10)		928,200	931	7,000	921,200
7						
8	BPA LT Transm Prepaid		2,400,000			2,400,000
9						
10	RTO Grid West N/R- WA (5)	211,234		904	46,941	164,293
11						
12	Contra RTO Grid West N/R - WA	-211,234	211,234			
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
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36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	57,976,248				52,116,892

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 233 Line No.: 5 Column: d

Account 102
Account 107
Account 539

Schedule Page: 233 Line No.: 23 Column: d

Account 142
Account 232
Account 557

Schedule Page: 233 Line No.: 40 Column: d

Account 165
Account 241
Account 282.1
Account 409.1

Schedule Page: 233 Line No.: 42 Column: d

Account 165
Account 232

Schedule Page: 233 Line No.: 46 Column: d

Account 181
Account 186
Account 923

Schedule Page: 233.1 Line No.: 2 Column: d

Account 228
Account 143

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Employee Benefits	294,345,786	139,413,272
3	FAS 133 Derivatives	102,310,588	106,959,021
4	Regulatory Liability	319,921,216	43,693,148
5			
6			
7	Other	103,109,888	142,263,119
8	TOTAL Electric (Enter Total of lines 2 thru 7)	819,687,478	432,328,560
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)	819,687,478	432,328,560

Notes

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
CAPITAL STOCKS (Account 201 and 204)					
<p>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.</p> <p>2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.</p>					
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	Common Stock (Account 201)	750,000,000			
2	PacifiCorp is a wholly				
3	owned indirect subsidiary of				
4	MidAmerican Energy Holdings Company				
5					
6	TOTAL COMMON STOCK	750,000,000			
7					
8					
9	Preferred Stock (Account 204)				
10	5% Cumulative Preferred	126,533	100.00	110.00	
11	(American Stock Exchange)				
12					
13	Serial Preferred, Cumulative:	3,500,000			
14	4.52% Series		100.00	103.50	
15	7.00% Series		100.00		
16	6.00% Series		100.00		
17	5.00% Series		100.00	100.00	
18	5.40% Series		100.00	101.00	
19	4.72% Series		100.00	103.50	
20	4.56% Series		100.00	102.34	
21	No Par Serial Preferred	16,000,000			
22					
23	TOTAL PREFERRED STOCK	19,626,533			
24					
25					
26					
27					
28					
29					
30					
31					
32	Authorized and unissued Capital Stock				
33					
34					
35					
36					
37					
38					
39					
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41					
42					

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
357,060,915	3,417,945,896					1
						2
						3
						4
						5
357,060,915	3,417,945,896					6
						7
						8
						9
126,243	12,624,300					10
						11
						12
						13
2,065	206,500					14
18,046	1,804,600					15
5,930	593,000					16
41,908	4,190,800					17
65,959	6,595,900					18
69,890	6,989,000					19
84,592	8,459,200					20
						21
						22
414,633	41,463,300					23
						24
						25
						26
						27
						28
						29
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						32
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						34
						35
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Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
PacifiCorp			
FOOTNOTE DATA			

Schedule Page: 250 Line No.: 1 Column: d

This class of stock is not redeemable.

Schedule Page: 250 Line No.: 9 Column: a

Except as specifically noted, all preferred stock series trade as unlisted securities.

Schedule Page: 250 Line No.: 15 Column: d

This series of preferred stock is not redeemable.

Schedule Page: 250 Line No.: 16 Column: d

This series of preferred stock is not redeemable.

Schedule Page: 250 Line No.: 32 Column: a

Authorizations for the issuance of common stock by PacifiCorp to its immediate corporate parent, PPW Holdings LLC are as follows:

Oregon Public Utility Commission, Docket No. UF-4228, Order No. 06-417, dated July 17, 2006.

Washington Utilities and Transportation Commission, Docket No. UE-060974, Order No. 1, dated June 28, 2006.

Idaho Public Utilities Commission, Case No. PAC-E-06-7, Order No. 30099, dated July 7, 2006.

As of December 31, 2007 30,000,000 shares authorized; 30,000,000 available.

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Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/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	Account 211 Miscellaneous Paid-in Capital			
2	Additional Paid-in Capital			
3	Share based payments	1,973,218		
4	Tax benefit from stock option exercises	14,147,176		
5	Benefit plan separation	-3,575,760		
6	Capital contributions	414,950,000		
7	Gain on sale of ScottishPower stock	196,208		
8	Qualified production activity tax deduction	-1,275,241		
9	Contribution of Intermountain Geothermal	432,552		
10	Adoption of FASB Interpretation No. 48	275,803		
11				
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39				
40	TOTAL	427,063,956		

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 253 Line No.: 3 Column: b

Represents the fair value of stock options granted by Scottish Power plc for which certain performance measures were met in March 2005. These options became fully vested in May 2005.

Schedule Page: 253 Line No.: 4 Column: b

Represents the income tax deduction attributable to the exercise of stock options granted by Scottish Power plc, of which \$3,502,924 related to options exercised during the year ended December 31, 2007. This deduction is required to be recorded through an adjustment to additional paid-in-capital.

Schedule Page: 253 Line No.: 5 Column: b

Represents the effect of transferring benefit plans to PPM Energy as a result of the sale of PacifiCorp by Scottish Power plc. This is required to be recorded through an adjustment to additional paid-in-capital.

Schedule Page: 253 Line No.: 6 Column: b

Represents capital contributions to PacifiCorp (with no shares of stock issued) from its immediate corporate parent PPW Holdings LLC, of which \$200,000,000 were made during the year ended December 31, 2007.

Schedule Page: 253 Line No.: 7 Column: b

Represents a realized gain on stock related to separation of PPM Energy, Inc. participants from the deferred compensation plan, required to be recorded in additional paid-in-capital.

Schedule Page: 253 Line No.: 8 Column: b

Represents an equity adjustment related to IRC 199 qualified production activities.

Schedule Page: 253 Line No.: 9 Column: b

Represents contribution of Intermountain Geothermal Company to PacifiCorp from MidAmerican Energy Holdings Company ("MEHC") in March 2006, subsequent to the sale of PacifiCorp to MEHC.

Schedule Page: 253 Line No.: 10 Column: b

Represents the increase in paid-in capital resulting from the January 1, 2007 adoption of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109."

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
CAPITAL STOCK EXPENSE (Account 214)				
<p>1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.</p> <p>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.</p>				
Line No.	Class and Series of Stock (a)			Balance at End of Year (b)
1	Common Stock			41,101,062
2				
3	Preferred Stock:			
4	5.00% Serial			98,049
5	4.52% Serial			9,676
6	4.72% Serial			30,349
7	4.56% Serial			49,071
8				
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21				
22	TOTAL			41,288,207

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Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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LONG-TERM DEBT (Account 221, 222, 223 and 224)

- 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.
- In column (a), for new issues, give Commission authorization numbers and dates.
- For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
- 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.
- For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
- In column (b) show the principal amount of bonds or other long-term debt originally issued.
- In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
- 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.
- 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	Bonds: (Account 221)		
2	First Mortgage Bonds:		
3			
4	4.300% Series due September 15, 2008	200,000,000	1,322,659
5			288,000 D
6	8.271% Series due October 1, 2010	48,972,000	
7	7.978% Series due October 1, 2011	4,422,000	
8	6.900% Series due November 15, 2011	500,000,000	3,567,009
9			1,735,000 D
10	8.493% Series due October 1, 2012	19,772,000	
11	8.797% Series due October 1, 2013	16,203,000	
12	5.450% Series due September 15, 2013	200,000,000	1,422,659
13			232,000 D
14	4.950% Series due August 15, 2014	200,000,000	1,442,365
15			728,000 D
16	8.734% Series due October 1, 2014	28,218,000	
17	8.294% Series due October 1, 2015	46,946,000	
18	8.635% Series due October 1, 2016	18,750,000	
19	8.470% Series due October 1, 2017	19,609,000	
20	7.700% Series due November 15, 2031	300,000,000	2,874,150
21			864,000 D
22	5.900% Series due August 15, 2034	200,000,000	1,892,365
23			722,000 D
24	5.25% Series due June 15, 2035	300,000,000	2,912,055
25			1,080,000 D
26	6.10% Series due August 1, 2036	350,000,000	2,908,372
27			1,141,000 D
28	5.75% Series due April 1, 2037	600,000,000	588,610
29			24,000 D
30	6.25% Series due October 15, 2037	600,000,000	5,091,953
31			750,000 D
32	7.67% Series C Medium-Term Notes due Jan. 10, 2007	5,724,000	36,625
33	TOTAL	5,421,486,000	57,859,191

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
						2
						3
09/15/2003	09/15/2008	09/15/2003	09/15/2008	200,000,000	8,600,000	4
						5
04/15/1992	10/01/2010	04/15/1992	10/01/2010	13,200,000	1,324,084	6
04/15/1992	10/01/2011	04/15/1992	10/01/2011	1,469,000	135,207	7
11/15/2001	11/15/2011	11/15/2001	11/15/2011	500,000,000	34,500,000	8
						9
04/15/1992	10/01/2012	04/15/1992	10/01/2012	7,988,000	757,533	10
04/15/1992	10/01/2013	04/15/1992	10/01/2013	7,542,000	724,499	11
09/15/2003	09/15/2013	11/15/2001	09/15/2013	200,000,000	10,900,000	12
						13
08/24/2004	08/15/2014	08/24/2004	08/15/2014	200,000,000	9,900,000	14
						15
04/15/1992	10/01/2014	04/15/1992	10/01/2014	14,492,000	1,361,369	16
04/15/1992	10/01/2015	04/15/1992	10/01/2015	25,697,000	2,268,533	17
04/15/1992	10/01/2016	04/15/1992	10/01/2016	11,159,000	1,015,390	18
04/15/1992	10/01/2017	04/15/1992	10/01/2017	12,288,000	1,089,327	19
11/15/2001	11/15/2031	11/15/2001	11/15/2031	300,000,000	23,100,000	20
						21
08/24/2004	08/15/2034	08/24/2004	08/15/2034	200,000,000	11,875,000	22
						23
06/13/2005	06/15/2035	06/13/2005	06/15/2035	300,000,000	15,750,000	24
						25
08/10/2006	08/01/2036	08/10/2006	08/01/2036	350,000,000	21,350,000	26
						27
03/14/2007	04/01/2037	03/14/2007	04/01/2037	600,000,000	27,504,166	28
						29
10/03/2007	10/15/2037	10/03/2007	10/15/2037	600,000,000	9,166,666	30
						31
01/10/1992	01/10/2007	01/10/1992	01/10/2007		10,976	32
				5,123,205,000	278,731,910	33

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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LONG-TERM DEBT (Account 221, 222, 223 and 224)

- 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.
- In column (a), for new issues, give Commission authorization numbers and dates.
- For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
- 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.
- For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
- In column (b) show the principal amount of bonds or other long-term debt originally issued.
- In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
- 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.
- 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	6.625% Series G Medium-Term Notes due June 1, 2007	100,000,000	1,267,428
2			630,000 D
3	7.43% Series E Medium-Term Notes due Sept. 11, 2007	2,000,000	15,530
4	7.22% Series E Medium-Term Notes due Sept. 18, 2007	2,500,000	19,412
5	7.27% Series E Medium-Term Notes due Sept. 24, 2007	4,000,000	31,059
6	6.375% Series H Medium-Term Notes due May 15, 2008	200,000,000	1,416,179
7			644,000 D
8	7.00% Series H Medium-Term Notes due Jul. 15, 2009	125,000,000	1,976,904
9			451,250 D
10	9.15% Series C Medium-Term Notes due Aug. 9, 2011	8,000,000	75,327
11	8.95% Series C Medium-Term Notes due Sept. 1, 2011	25,000,000	175,398
12	8.95% Series C Medium-Term Notes due Sept. 1, 2011	20,000,000	132,118
13	8.92% Series C Medium-Term Notes due Sept. 1, 2011	20,000,000	188,318
14	8.29% Series C Medium-Term Notes due Dec. 30, 2011	3,000,000	23,040
15	8.26% Series C Medium-Term Notes due Jan. 10, 2012	1,000,000	7,649
16	8.28% Series C Medium-Term Notes due Jan. 10, 2012	2,000,000	13,297
17	8.25% Series C Medium-Term Notes due Feb. 1, 2012	3,000,000	22,946
18	8.13% Series E Medium-Term Notes due Jan. 22, 2013	10,000,000	75,827
19	8.53% Series C Medium-Term Notes due Dec. 16, 2021	15,000,000	115,202
20	8.375% Series C Medium-Term Notes due Dec. 31, 2021	5,000,000	38,400
21	8.26% Series C Medium-Term Notes due Jan. 7, 2022	5,000,000	33,243
22	8.27% Series C Medium-Term Notes due Jan. 10, 2022	4,000,000	30,594
23	8.05% Series E Medium-Term Notes due Sept. 1, 2022	15,000,000	131,471
24	8.07% Series E Medium-Term Notes due Sept. 9, 2022	8,000,000	70,118
25	8.12% Series E Medium-Term Notes due Sept. 9, 2022	50,000,000	438,238
26	8.11% Series E Medium-Term Notes due Sept. 9, 2022	12,000,000	105,177
27	8.05% Series E Medium-Term Notes due Sept. 14, 2022	10,000,000	87,648
28	8.08% Series E Medium-Term Notes due Oct. 14, 2022	26,000,000	208,198
29	8.08% Series E Medium-Term Notes due Oct. 14, 2022	25,000,000	200,190
30	8.23% Series E Medium-Term Notes due Jan. 20, 2023	5,000,000	37,914
31	8.23% Series E Medium-Term Notes due Jan. 20, 2023	4,000,000	30,331
32			-81,560 P
33	TOTAL	5,421,486,000	57,859,191

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
06/09/1995	06/01/2007	06/09/1995	06/01/2007		2,760,417	1
						2
09/11/1992	09/11/2007	09/11/1992	09/11/2007		103,194	3
09/18/1992	09/18/2007	09/18/1992	09/18/2007		128,857	4
09/22/1992	09/24/2007	09/22/1992	09/24/2007		212,446	5
05/12/1998	05/15/2008	05/12/1998	05/15/2008	200,000,000	12,750,000	6
						7
07/15/1997	07/15/2009	07/15/1997	07/15/2009	125,000,000	8,750,000	8
						9
08/09/1991	08/09/2011	08/09/1991	08/09/2011	8,000,000	732,000	10
08/16/1991	09/01/2011	08/16/1991	09/01/2011	25,000,000	2,237,500	11
08/16/1991	09/01/2011	08/16/1991	09/01/2011	20,000,000	1,790,000	12
08/16/1991	09/01/2011	08/16/1991	09/01/2011	20,000,000	1,784,000	13
12/31/1991	12/30/2011	12/31/1991	12/30/2011	3,000,000	248,700	14
01/09/1992	01/10/2012	01/09/1992	01/10/2012	1,000,000	82,600	15
01/10/1992	01/10/2012	01/10/1992	01/10/2012	2,000,000	165,600	16
01/15/1992	02/01/2012	01/15/1992	02/01/2012	3,000,000	247,500	17
01/20/1993	01/22/2013	01/20/1993	01/22/2013	10,000,000	813,000	18
12/16/1991	12/16/2021	12/16/1991	12/16/2021	15,000,000	1,279,500	19
12/31/1991	12/31/2021	12/31/1991	12/31/2021	5,000,000	418,750	20
01/08/1992	01/07/2022	01/08/1992	01/07/2022	5,000,000	413,000	21
01/09/1992	01/10/2022	01/09/1992	01/10/2022	4,000,000	330,800	22
09/18/1992	09/01/2022	09/18/1992	09/01/2022	15,000,000	1,207,500	23
09/09/1992	09/09/2022	09/09/1992	09/09/2022	8,000,000	645,600	24
09/11/1992	09/09/2022	09/11/1992	09/09/2022	50,000,000	4,060,000	25
09/11/1992	09/09/2022	09/11/1992	09/09/2022	12,000,000	973,200	26
09/14/1992	09/14/2022	09/14/1992	09/14/2022	10,000,000	805,000	27
10/15/1992	10/14/2022	10/15/1992	10/14/2022	26,000,000	2,100,800	28
10/15/1992	10/14/2022	10/15/1992	10/14/2022	25,000,000	2,020,000	29
01/20/1993	01/20/2023	01/20/1993	01/20/2023	5,000,000	411,500	30
01/29/1993	01/20/2023	01/29/1993	01/20/2023	4,000,000	329,200	31
						32
				5,123,205,000	278,731,910	33

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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LONG-TERM DEBT (Account 221, 222, 223 and 224)

- 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.
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- For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
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- For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
- In column (b) show the principal amount of bonds or other long-term debt originally issued.
- In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
- 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.
- 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	7.26% Series F Medium-Term Notes due July 21, 2023	27,000,000	246,981
2	7.26% Series F Medium-Term Notes due July 21, 2023	11,000,000	100,622
3	7.23% Series F Medium-Term Notes due Aug. 16, 2023	15,000,000	137,211
4	7.24% Series F Medium-Term Notes due Aug. 16, 2023	30,000,000	274,423
5	6.75% Series F Medium-Term Notes due Sept. 14, 2023	5,000,000	38,250
6	6.75% Series F Medium-Term Notes due Sept. 14, 2023	2,000,000	15,300
7	6.72% Series F Medium-Term Notes due Sept. 14, 2023	2,000,000	15,300
8	6.75% Series F Medium-Term Notes due Oct. 26, 2023	20,000,000	152,326
9	6.75% Series F Medium-Term Notes due Oct. 26, 2023	16,000,000	121,861
10	6.75% Series F Medium-Term Notes due Oct. 26, 2023	12,000,000	91,396
11	6.71% Series G Medium-Term Notes due Jan. 15, 2026	100,000,000	904,467
12	Subtotal - First Mortgage Bonds	4,608,116,000	42,331,805
13			
14	Pollution Control Obligations - Secured by Pledged First Mortgage Bonds:		
15			
16	Poll Ctrl Rev Refunding Bonds, Moffat County, CO, Series 1994	40,655,000	874,159
17	5-5/8% Poll Ctrl Rev Refunding Bonds, Lincoln County, WY, Series 1993	8,300,000	228,980
18			197,125 D
19	5.65% Poll Ctrl Rev Refunding Bonds, Emery County, Utah, Series 1993A	46,500,000	1,624,793
20	5-5/8% Poll Ctrl Rev Refunding Bonds, Emery County, Utah, Series 1993B	16,400,000	625,551
21			389,500 D
22	Poll Ctrl Rev Refunding Bonds, Sweetwater County, WY, Series 1994	21,260,000	510,479
23	Poll Ctrl Rev Refunding Bonds, Converse County, WY, Series 1994	8,190,000	209,777
24	Poll Ctrl Rev Refunding Bonds, Emery County, UT, Series 1994	121,940,000	3,274,246
25	Poll Ctrl Rev Refunding Bonds, Carbon County, UT, Series 1994	9,365,000	206,519
26	Poll Ctrl Rev Refunding Bonds, Lincoln County, WY, Series 1994	15,060,000	422,858
27	Poll Ctrl Rev Refunding Bonds, Converse County, WY, Series 1988	17,000,000	155,970
28	Poll Ctrl Revenue Bonds, Sweetwater County, WY, Series 1984	15,000,000	122,887
29			105,000 D
30	Poll Ctrl Rev Refunding Bonds, Lincoln Crnty, WY, Series 1991	45,000,000	771,836
31	Poll Ctrl Revenue Bonds, City of Forsyth, MT, Series 1986	8,500,000	304,824
32	Environ. Imprvmnt Rev Bonds, Converse County, WY, Series 1995	5,300,000	132,043
33	TOTAL	5,421,486,000	57,859,191

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
07/22/1993	07/21/2023	07/22/1993	07/21/2023	27,000,000	1,960,200	1
07/22/1993	07/21/2023	07/22/1993	07/21/2023	11,000,000	798,600	2
08/16/1993	08/16/2023	08/16/1993	08/16/2023	15,000,000	1,084,500	3
08/16/1993	08/16/2023	08/16/1993	08/16/2023	30,000,000	2,172,000	4
09/14/1993	09/14/2023	09/14/1993	09/14/2023	5,000,000	337,500	5
09/14/1993	09/14/2023	09/14/1993	09/14/2023	2,000,000	135,000	6
09/14/1993	09/14/2023	09/14/1993	09/14/2023	2,000,000	134,400	7
10/26/1993	10/26/2023	10/26/1993	10/26/2023	20,000,000	1,350,000	8
10/26/1993	10/26/2023	10/26/1993	10/26/2023	16,000,000	1,080,000	9
10/26/1993	10/26/2023	10/26/1993	10/26/2023	12,000,000	810,000	10
01/23/1996	01/15/2026	01/23/1996	01/15/2026	100,000,000	6,710,000	11
				4,384,835,000	245,705,614	12
						13
						14
						15
11/17/1994	05/01/2013	11/17/1994	05/01/2013	40,655,000	1,585,074	16
11/15/1993	11/01/2021	11/15/1993	11/01/2021	8,300,000	468,543	17
						18
11/15/1993	11/01/2023	11/15/1993	11/01/2023	46,500,000	2,636,594	19
11/15/1993	11/01/2023	11/15/1993	11/01/2023	16,400,000	925,796	20
						21
11/17/1994	11/01/2024	11/17/1994	11/01/2024	21,260,000	833,632	22
11/17/1994	11/01/2024	11/17/1994	11/01/2024	8,190,000	316,422	23
11/17/1994	11/01/2024	11/17/1994	11/01/2024	121,940,000	4,981,354	24
11/17/1994	11/01/2024	11/17/1994	11/01/2024	9,365,000	369,844	25
11/17/1994	11/01/2024	11/17/1994	11/01/2024	15,060,000	606,459	26
01/01/1988	01/01/2014	01/01/1988	01/01/2014	17,000,000	680,435	27
12/01/1984	12/01/2014	12/01/1984	12/01/2014	15,000,000	600,430	28
						29
01/17/1991	01/01/2016	01/17/1991	01/01/2016	45,000,000	1,639,795	30
12/01/1986	12/01/2016	12/01/1986	12/01/2016	8,500,000	359,492	31
11/17/1995	11/01/2025	11/17/1995	11/01/2025	5,300,000	224,278	32
				5,123,205,000	278,731,910	33

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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LONG-TERM DEBT (Account 221, 222, 223 and 224)

- 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.
- In column (a), for new issues, give Commission authorization numbers and dates.
- For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
- 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.
- For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
- In column (b) show the principal amount of bonds or other long-term debt originally issued.
- In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
- 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.
- 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	Environ. Imprvmnt Rev Bonds, Lincoln County, WY, Series 1995	22,000,000	404,262
2	Subtotal Pollution Control Obligations - Secured by Pledged First Mortgage Bonds	400,470,000	10,560,809
3			
4			
5	Pollution Control Obligations - Unsecured		
6			
7	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1992A	9,335,000	167,524
8	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1992B	6,305,000	151,908
9	Poll Ctrl Rev Refndng Bonds, Converse County, WY, Series 1992	22,485,000	242,163
10	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1988B	11,500,000	84,822
11	Poll Ctrl Rev Refndng Bonds, Sweetwater County, WY, Ser. 1990A	70,000,000	660,750
12	Poll Ctrl Rev Refndng Bonds, Emery County, UT, Series 1991	45,000,000	872,505
13	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1988A	50,000,000	422,443
14	Poll Ctrl Rev Refndng Bonds, City of Forsyth, MT, Series 1988	45,000,000	380,198
15	Poll Ctrl Rev Refndng Bonds, City of Gillette, WY, Ser. 1988	41,200,000	351,905
16	Environ. Imprvmnt Rev Bonds, Sweetwater County, WY, Series 1995	24,400,000	225,000
17	6.150% Environ. Imprvmnt Rev Bonds, Emery County, UT, Series 1996	12,675,000	556,549
18			178,464 D
19			
20	Subtotal - Pollution Control Obligations - Unsecured	337,900,000	4,294,231
21			
22			
23			
24	TOTAL ACCOUNT 221	5,346,486,000	57,186,845
25			
26			
27	Reacquired Bonds: (Account 222)		
28			
29			
30	Advances from Associated Companies: (Account 223)		
31			
32			
33	TOTAL	5,421,486,000	57,859,191

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
11/17/1995	11/01/2025	11/17/1995	11/01/2025	22,000,000	952,183	1
				400,470,000	17,180,331	2
						3
						4
						5
						6
09/29/1992	12/01/2020	09/29/1992	12/01/2020	9,335,000	376,057	7
09/29/1992	12/01/2020	09/29/1992	12/01/2020	6,305,000	253,995	8
09/29/1992	12/01/2020	09/29/1992	12/01/2020	22,485,000	907,984	9
01/01/1988	01/01/2014	01/01/1988	01/01/2014	11,500,000	499,655	10
07/25/1990	07/01/2015	07/25/1990	07/01/2015	70,000,000	3,042,320	11
05/23/1991	07/01/2015	05/23/1991	07/01/2015	45,000,000	1,968,893	12
01/01/1988	01/01/2017	01/01/1988	01/01/2017	50,000,000	2,179,830	13
01/01/1988	01/01/2018	01/01/1988	01/01/2018	45,000,000	1,950,960	14
01/01/1988	01/01/2018	01/01/1988	01/01/2018	41,200,000	1,797,533	15
12/14/1995	11/01/2025	12/14/1995	11/01/2025	24,400,000	1,076,726	16
09/24/1996	09/01/2030	09/24/1996	09/01/2030	12,675,000	779,512	17
						18
						19
				337,900,000	14,833,465	20
						21
						22
						23
				5,123,205,000	277,719,410	24
						25
						26
						27
						28
						29
						30
						31
						32
				5,123,205,000	278,731,910	33

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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LONG-TERM DEBT (Account 221, 222, 223 and 224)

- 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.
- In column (a), for new issues, give Commission authorization numbers and dates.
- For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
- 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.
- For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
- In column (b) show the principal amount of bonds or other long-term debt originally issued.
- In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
- 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.
- 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			
2	Other Long-Term Debt: (Account 224)		
3	57.48 Series No Par Serial Preferred Stock	75,000,000	672,346
4			
5	TOTAL ACCOUNT 224	75,000,000	672,346
6			
7			
8	Long-Term Debt Authorized but Unissued		
9			
10			
11			
12			
13			
14			
15			
16			
17			
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22			
23			
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30			
31			
32			
33	TOTAL	5,421,486,000	57,859,191

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
						2
06/11/1992	06/15/2007	07/01/2003	06/15/2007		1,012,500	3
						4
					1,012,500	5
						6
						7
						8
						9
						10
						11
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						31
						32
				5,123,205,000	278,731,910	33

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 256 Line No.: 28 Column: a

On March 14, 2007, PacifiCorp issued \$600 million of its 5.75% Series of First Mortgage Bonds due April 1, 2037. PacifiCorp used the proceeds for general corporate purposes, including the reduction of short-term debt. State commission authorizations for this issuance were as follows:

Utah Public Service Commission, Docket No. 07-035-05, Report and Order dated March 2, 2007.

Oregon Public Utility Commission, Docket No. UF-4237, Order No. 07-085, dated March 5, 2007.

Washington Utilities and Transportation Commission, Docket No. UE-070450, Order No. 1, dated March 7, 2007.

Idaho Public Utilities Commission, Case No. PAC-E-07-2, Order No. 30258, dated February 27, 2007.

Schedule Page: 256 Line No.: 30 Column: a

On October 3, 2007, PacifiCorp issued \$600 million of its 6.25% Series of First Mortgage Bonds due October 15, 2037. PacifiCorp intends to use the proceeds for general corporate purposes, including the reduction of short-term debt. State commission authorizations for this issuance were as follows:

Oregon Public Utility Commission, Docket No. UF-4237, Order No. 07-085, dated March 5, 2007.

Idaho Public Utilities Commission, Case No. PAC-E-07-2, Order No. 30258, dated February 27, 2007.

Schedule Page: 256.4 Line No.: 3 Column: a

As of December 31, 2007, there were no shares outstanding. On June 15, 2007 the remaining 375,000 shares outstanding (\$100 stated value per share) on the \$7.48 series were redeemed in accordance with the mandatory redemption requirements.

Schedule Page: 256.4 Line No.: 8 Column: a

For authorization for the issuance of long-term debt (\$1.5 billion authorized; \$300 million available as of December 31, 2007), refer to page 104, *Important Changes During the Year*, Item 6, of this Form No. 1.

Authorization for the issuance of pollution control revenue bonds (\$125 million authorized; \$79 million available as of December 31, 2007) is as follows:

Oregon Public Utility Commission, Docket No. UF-4128, Order No. 95-518, dated May 25, 1995.

Washington Utilities and Transportation Commission, Docket No. UE-950490, dated May 24, 1995.

Idaho Public Utilities Commission, Docket No. PAC-S-95-2, Order No. 26039, dated June 13, 1995.

For additional information regarding long-term debt, refer to page 104, *Important Changes During the Year*, ITEM 6, of this Form No. 1.



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(Next Page is 261)

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	438,888,867
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8	Other	100,881,143
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13	Other	988,435,434
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18	Other	32,504,936
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25	Other	1,027,196,502
26	State Tax Deductions	16,096,307
27	Federal Tax Net Income	452,407,699
28	Show Computation of Tax:	
29		
30	Federal Income Tax at 35.00%	158,342,695
31	Federal Accrual to Return Adjustments	5,203,656
32	Tax Reserve Changes	5,649,016
33	Stock Options to APIC	3,083,876
34	Wind Credits	-10,145,039
35	Mining Rescue Training Credits	-46,485
36	Current Federal Tax Interest	-6,013,353
37	Deferred Correction/ Uncertain Position	-11,522,396
38	Misc. Reclass	-130
39		
40	Federal Income Tax Accrual	144,551,840
41		
42		
43		
44		

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
PacifiCorp			
FOOTNOTE DATA			

Schedule Page: 261 Line No.: 8 Column: a

Particulars (Details)	Amounts
Contributions in Aid of Construction	65,638,746
Highway Relocation	29,268,520
Hermiston Swap	263,341
Unearned Joint Use Pole Contract Revenue	57,066
Accrued Royalties	593,042
FAS 115 Unrealized Gain/Loss	1,337,775
Bridger Coal Company Reclamation Trust Earnings PMI	5,438,803
Equity Earnings in Subsidiaries	-1,716,150
Total	100,881,143

Schedule Page: 261 Line No.: 13 Column: a

Particulars (Details)	Amounts
Fed/State Tax Expense	219,340,007
% capitalized labor costs for Powertax input	2,990,606
Mandatory Redeemable Preferred Stock - FAS 150	1,096,543
Meals & Entertainment	655,934
Penalties	4,182,180
Penalties- PMI	18,407
Lobbying expenses	1,101,453
Meals & Entertainment - Bridger Coal	22,597
MEHC Insurance Services - Premium	7,057,172
Mining Rescue Training Credit Addback	28,527
Non-deductible Parachute Payment - 280G	1,623,557
Deferred Revenue - SRC	119,015
PMI Fuel Tax Cr	17,957
Interest Accual on FIT - Cash Basis	464,179
Mining Rescue Training Credit Addback	17,958
30% capitalized labor costs for Powertax input	3,835,385
Book Depreciation	495,661,102
Tax vs Book Depreciation - PMI	11,171,996
Avoided Costs	56,119,565
ARO - reclass to ARO liabilities	5,075,961
Book Gain/Loss on Land Sales	11,491,995
Book Cost Depletion - Addback	2,046,969
Book Depletion -SRC	215,634
Book Depletion-Step up basis adjustment	156,365
Fixed Asset -Book/Tax	545,064
Book Amort-Bandoned Proj-Lease Rights	505,367
Book Amort-Bandoned Proj-Lease Rental	20,825
May 2000 Transition Plan Costs-OR	3,892,299
Glenrock Excluding Reclamation-UT	1,302,399
FAS 87/88 Pension Writeoff - UT rate order	3,159,014
98 Early Retirement-OR rate order	3,676,946
Reg Asset - FAS 158 Pension Liab Adj.	23,767,760
Reg Asset - FAS 158 Post Ret. Liab.	19,311,911
Environmental Clean-up Accrual	4,852,132
Environmental Costs - WA	100,476
Cholla Plt Transact Costs-APS Amort	938,633
WA Disallowed Colstrip #3-Write-off	52,188
Wyoming PCAM Def Net Power Costs	1,673,388

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
PacifiCorp			
FOOTNOTE DATA			

IDAI Costs - direct access	333,105
SB 1149-Related Regulatory Assets	8,017,105
Deferred Intervener Funding Grants	269,486
RTO Grid West Notes Receivable - ID	27,162
OR SB 408 Recovery	2,092,338
Weatherization	504,628
Trojan Decommissioning Costs - Regulatory	1,532,586
781 Shopping Incentive	378,787
SB 1149 Costs	1,184,975
Post Merger Loss-Reacq Debt - Addback	4,651,715
Trapper Mining Stock Basis	256,060
Prepaid Insurance - IBEW 157 contingency reserve	182,213
Prepaid Taxes - Property Taxes	1,400,646
RTO Grid West Note Receivable - w/o - WA	46,941
TGS Buyout	15,474
Lakeview Buyout	43,280
Joseph Settlement	137,381
FAS 133 Derivatives - Current	12,242,658
Energy trading derivatives -noncurrent	33,891
ARO Reg Liabilities	4,912,316
Non-ARO Liability - Reg Liability	8,763,878
Reg Liability - UT Home Energy Lifeline	156,028
Reg Liability - WA Low Energy Program	26,909
Reg Liab - OR Balance Consol	48,602
Oregon Gain on Sale	13,875
West Valley Lease Reduction - ID	382,653
West Valley Lease Reduction - WY	848,461
A&G Credit - WA	42,438
A&G Credit - ID	399,549
A&G Credit - WY	890,855
Reg Liability-Blue Sky Program OR	462,671
Reg Liability-Blue Sky Program WA	81,041
Reg Liability-Blue Sky Program CA	34,975
Reg Liability-Blue Sky Program UT	589,668
Reg Liability-Blue Sky Program ID	19,977
Reg Liability-Blue Sky Program WY	104,551
FAS 158 SERP Liability	42,000
FAS 133 Derivatives - noncurrent	12,248,513
Distribution O&M Amort of Writeoff	45,384
Sec. 263A Inventory Change - PMI	532,054
Def Reg Asset-Transmission Svc Deposit	11,523,653
Bear River Settlement Agreement	491,262
Misc Def Dr-Prop Damage Repairs	28,493
BPA Conservation Rate Credit	827,852
N. Umpqua Settlement Agreement	1,118,623
Umpqua Settlement Agreement	638,092
Trail Mountain Accrued Liabilities	416,967
Purchase Card Trans Povision	1,005,134
WV Contract Termination Fee Accrual	6,601,499
Bridger Coal Company Gain/Loss on Assets Disposed	3,839,523
Misc. Deferred Credits	225,811
Injuries and Damages Accrual - Cash Basis	1,415,357
FAS 112 Book Reserve	103,076

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PacifiCorp			
FOOTNOTE DATA			

Bridger Coal Company ARO - Asset	7,132,809
Bridger Coal Company Extraction Taxes Payable - PMI	654,468
Vacation Accrual - PMI	106,520
	<u>988,435,434</u>

Schedule Page: 261 Line No.: 18 Column: a

Particulars (Details)	Amounts
Utah Deferred Comp / COLI	(4,242,716)
MEHC Insurance Services - Receivable	(13,843,526)
Medicare Subsidy	(11,206,000)
Bridger Coal Tax Exempt Interest Income	(25,025)
Dividend Received Deduction	(623,236)
SMUD Revenue Imputation-UT reg liab	(2,564,433)
	<u>(32,504,936)</u>

Schedule Page: 261 Line No.: 25 Column: a

Particulars (Details)	Amounts
PPL Pre - 1943 Preferred Stock Div - Deduction	(381,063)
Tax Exempt Interest (No AMT)	(618)
2004 JCA - Qualified Production Activities Deduction (6%)	(10,900,494)
2004 JCA - Qualified Production Activities Deduction (6%) PMI	(418,845)
Bridger Coal Company Depletion - PMI	(3,306,068)
PMI Overriding Coal Royalty % Depletion	(22,306)
Tax Depreciation	(604,113,141)
Depreciation (Tax Depreciation M-1)	(13,970,551)
Capitalized Depreciation	(4,677,539)
AFUDC	(62,756,122)
Basis Intangible Difference	(6,807,377)
Gain / (Loss) on Prop. Disposition	(23,351,192)
Coal Mine Development	(543,329)
Coal Mine Extension	(1,324,159)
Removal Costs	(43,589,376)
Coal Mine Development- 30% Amortization	(847,960)
ARO - reclass to reg assets/liability & ARO liability	(8,763,878)
Tax Percentage Depletion - Deduction	(1,450,928)
Tax Depletion	(137,384)
Book/Tax Gain on Disposal	(2,637)
ARO Reg Assets	(1,571,275)
Def Reg Asset-OR Def Net Power Costs	(12,091)
Contra RTO Grid West N/R w/o - WA	(211,234)
RTO Grid West Notes Receivable - OR	(68,645)
Unrecovered Plant-Powerdale	(10,439,883)
Deferred Excess Net Power Costs-CA	(758,295)
Deferred Excess Net Power Costs-WY	(29,108,115)
Deferred UT Independent Evaluation Fee	(300,511)
ID MEHC 2006 Transition Costs	(1,830,583)
OR_RCAC Sep-Dec 07 Deferred	(1,633,653)
Regulatory asset - Net FAS 133	(26,186,602)
Coal Pile Inventory Adjustment	(105,373)
Prepaid Taxes - OR PUC	(31,726)
Prepaid Taxes - UT PUC	(160,057)
Prepaid Taxes - ID PUC	(18,240)

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PacifiCorp			
FOOTNOTE DATA			

Other Prepaid	(611,442)
WY Joint Water Board Reserve - Deduction	(300,000)
Wasatch workers comp reserve	(186,471)
Reg liability BPA balancing accounts	(14,142,869)
OR Rate Refunds	(5)
OR Reg Asset/Liability Consolidation	(468,072)
Property Insurance(same as Injuries & Damages)	(2,233,114)
West Valley Lease Reduction - WA	(342,758)
West Valley Lease Reduction - CA	(23,868)
West Valley Lease Reduction - UT	(946,291)
CA-California Alternative Rate for Energy Program (CARE)	(352,495)
A&G Credit - CA	(38,231)
March 2006 Transition Plan Costs _WA	(1,623,722)
Self Insured Health Benefit	(121,587)
Vacation Accrual - Cash Basis (2.5 mos)	(839,899)
Accrued Retention Bonus	(58,333)
Deferred Compensation Accrual - Cash Basis	(6,385,866)
Pension / Retirement Accrual - Cash Basis	(153,688)
Severance Accrual - Cash Basis	(174,639)
Accrued CIC Severance	(13,418,126)
FAS 158 Pension Liability	(39,487,083)
FAS 158 Post-Retirement Liability	(9,176,369)
FAS 143 ARO Liability	(8,417,002)
Scottish Power Long Term Incentive Plan	(2,324,715)
M&S Inventory Write-Off	(127,937)
Bad Debts Allowance - Cash Basis	(4,973,203)
Amort of Projects-Klamath Engineering	(6,423)
R & E - Sec.174 Deduction	(6,782,736)
Def Reg Asset-Foote Creek Contract	(137,640)
Deferred Regulatory Expense	(927)
Tenant Lease Allow - PSU Call Cntr	(62,756)
Other Environmental Liabilities	(7,140,683)
Amort of Debt Disc & Exp	(56,166)
Duke/Hermiston Contract Renegotiation	(754,839)
Idaho Customer Balancing Account	(9,249,021)
Special Assessment - DOE	(38,625)
Misc. Current and Accrued Liability	(10,119,572)
Reverse Accrued Final Reclamation	(700,335)
PMI Devt Cost Amort	(1,152,215)
PMI EITF04-6 Pre-Stripping Costs	(1,093,541)
Microsoft Software License Liability	(532,374)
MCI FOG Wire Lease	(210)
NW Power Act-WA	(4,271,640)
Redding Contract - Prepaid	(549,996)
Amort NOPAs 99-00 RAR	(41,311)
Bridger Coal Company ARO - Liability	(3,030,408)
Bridger Coal Company ARO - Reg Asset	(4,102,401)
Coal Mine Extension Costs-PP&E - PMI	(462,425)
Coal Mine Developent-PMI	(775,310)
Bridger Coal Company Underground Mine Cost Depletion	(175,792)
PacifiCorp Stock Incentive Plan	(3,865,252)
PacifiCorp Executive Stock Option Plan	(938,127)
Scottish Power Long Term Incentive Plan	(4,426,742)

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PacifiCorp			
FOOTNOTE DATA			

Total

(1,027,196,502)

Schedule Page: 261 Line No.: 40 Column: b

On March 21, 2006, a wholly owned subsidiary of MidAmerican Energy Holdings Company ("MEHC") acquired 100% of the common stock of PacifiCorp from a wholly owned subsidiary of Scottish Power plc ("ScottishPower"). As a result of this acquisition, MEHC controls substantially all of PacifiCorp's voting securities, which include both common and preferred stock. MEHC, a holding company based in Des Moines, Iowa, owning subsidiaries that are principally engaged in energy businesses, is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

Names of group members who will file a consolidated Federal Tax Return:

Under MEHC:

PPW Holdings LLC Sub-Group:

PacifiCorp

PacifiCorp Sub-Group:

Centralia Mining Company

Energy West Mining Company

Glenrock Coal Company

Intermountain Geothermal Company

Interwest Mining Company

Pacific Minerals, Inc.

PacifiCorp Environmental Remediation Company

PacifiCorp Future Generations, Inc.

PacifiCorp Investment Management, Inc.

Steam Reserve Corporation

MEHC Sub-Group:

Academy of Real Estate, Inc

Allerton Capital, Ltd

American Pacific Finance Company

American Pacific Finance Company II

CalEnergy Company, Inc

CalEnergy Generation Operating Company

CalEnergy Holdings, Inc

CalEnergy Imperial Valley Company, Inc

CalEnergy International Services, Inc

CalEnergy International, Inc

CalEnergy Minerals LLC

CalEnergy Pacific Holdings Corp

CalEnergy UK Inc

Capitol Intermediary Company

Capitol Land Exchange, Inc

Capitol Title Company

CBEC Railway, Inc

CBSHome Real Estate Company

CBSHome Real Estate of Iowa, Inc

CBSHome Relocation Services, Inc

CE Administrative Services, Inc

CE Electric (NY), Inc

CE Electric, Inc

CE Exploration Company

CE Geothermal, Inc.

CE Indonesia Geothermal, Inc

CE International Investments, Inc

CE Power, Inc

Champion Realty, Inc

Chancellor Insurance Services, Inc

Chancellor Title Services, Inc

Cimmred Leasing Company

Columbia Title of Florida, Inc

Community Diversified Investments, Inc

Cordova Funding Corporation

Dakota Dunes Development Company

DCCO, Inc

Edina Financial Services, Inc

Edina Realty Referral Network

Edina Realty Relocation, Inc

Edina Realty Title, Inc

Edina Realty, Inc

Esslinger-Wooten-Maxwell, Inc

E-W-M Referral Services, Inc.

FFR, Inc

First Realty, Ltd

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FOOTNOTE DATA			

MEHC Sub-Group (continued):

First Reserve Insurance, Inc
For Rent, Inc
HMSV Financial Services, Inc
HN Real Estate Group N.C., Inc.
HN Real Estate Group, LLC
HN Referral Corporation
Home Real Estate, Inc
HomeServices Financial Holdings, Inc
HomeServices Financial, LLC
HomeServices Financial-Iowa, LLC
HomeServices Insurance, Inc
HomeServices of Alabama, Inc.
HomeServices of America, Inc
HomeServices of California, Inc
HomeServices of Florida, Inc
HomeServices of Iowa, Inc
HomeServices of Kentucky, Inc
HomeServices of Nebraska, Inc
HomeServices of Nevada, Inc
HomeServices of the Carolinas, Inc
HomeServices Pacific Northwest, Inc.
HomeServices Relocation, LLC
HSR Equity Funding, Inc
Huff Commercial Group, LLC
Huff-Drees Realty, Inc.
IMO Company, Inc
InterCoast Capital Company
InterCoast Energy Company
InterCoast Power Company
InterCoast Sierra Power Company
Iowa Realty Company, Inc
Iowa Realty Insurance Agency, Inc
Iowa Title Company
IWG Co 8
J.S. White Associates, Inc
JBRC, Inc.
JD Reece Mortgage Company
Jenny Pruitt & Associates
Jim Huff Realty, Inc.
JP & A, Inc
JRHBW Realty, Inc d/b/a RealtySouth
Kansas City Title, Inc
Kern River Funding Corporation

KR Holding, LLC
Larabee School of Real Estate & Insurance
MEC Construction Services Company
MEHC Insurance Services Ltd.
MEHC Investment, Inc
MHC Investment Company
MHC, Inc
Mid-America Referral Network, Inc.
MidAmerican Comercial R.E. Services, Inc
MidAmerican Energy Company
MidAmerican Energy Holdings Company
MidAmerican Services Company
Midland Escrow Services, Inc
Midwest Capital Group, Inc
Midwest Gas Company
MWR Capital, Inc
Nebraska Land Title & Abstract Company
Northern Aurora Inc
Northern Natural Gas Company
Pickford Escrow Company, Inc
Pickford Real Estate, Inc
Pickford Services Company, Inc
Preferred Carolinas Realty, Inc
Professional Referral Organization, Inc
Quad Cities Energy Company
Real Estate Links, LLC
Real Estate Referral Network, inc
Reece & Nichols Alliance, Inc
Reece & Nichols Realtors, Inc
Referral Company of North Carolina, Inc
Roberts Brothers, Inc
Roberts Holding Company, Inc
Roy H. Long Realty Company, Inc
Salton Sea Minerals Corporation
San Diego PCRE, Inc
Semonin Realtors, Inc
The Escrow Firm
The Referral Company
Trinity Mortgage Partners, inc
TTP, Inc of South Dakota
Two Rivers, Inc
Woods Bros. Realty, Inc

With Respect to members of the MEHC Sub-Group, MEHC requires all subsidiaries to pay or receive from MEHC an amount of tax based primarily on the stand alone method of allocation. The computation includes all tax benefits from tax deductions stemming from cost borne by utility customers.

Berkshire Hathaway Inc. Sub-Group:

21st Communities, Inc.
21st Mortgage Corporation
21st SPC, Inc.

AAS-Lunken, Inc.
Acme Brick Block and Tile, Inc.
Acme Brick Company

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FOOTNOTE DATA			

Berkshire Hathaway Inc. Sub-Group:

Acme Brick DFW, Inc.	BNJ NetJets, Inc.
Acme Brick Sales Company	Boart U.S. Travel International, Ltd.
Acme Building Brands, Inc.	Boat America Corporation
Acme Investment Company	Boat U.S., Inc.
Acme Management Company	Boot Royalty Company
Acme Services Company, L.P.	Borsheim Jewelry Company Inc.
Adalet/Scott Fetzer Company	BR Agency, Inc.
AEG Processing Center No. 58, Inc.	Bricker-Mincolla Uniforms
AEG Processing Center No. 35, Inc.	Brilliant National Services, Inc.
Agile Mfg, Inc.	Brooks Sports, Inc. & Subsidiary
AJF Warehouse Distributors, Inc.	Brookwood Insurance Company
AL/TEX Homes, Inc.	Business Wire Canada Inc.
Alachua Tung Oil Company	Business Wire, Inc.
Albecca Inc.	C & R Insurance Services, Inc.
Alexander City Flying Services, Inc.	California Employer Group No. 27, Inc.
All Bilt Uniforms	California Insurance Company
Alpha Cargo Motor Exress, Inc.	Camp Manufacturing Company
American All Risk Insurance Services, Inc.	Campbell Hausfeld/Scott Fetzer Company
American Commercial Claims Administrators, Inc.	Carefree/Scott Fetzer Company
American Dairy Queen Corporation	Central States Indemnity Co. of Omaha
American Employers Group, Inc.	Central States of Omaha Companies, Inc.
American Tile Supply, Inc.	CG Service, Inc.
Anderson Hardwood Floors, Inc. (fka Shaw-Razor Floors)	Chippewa Shoe Company
Apeks Apparel, Inc.	CJE II, Inc.
Appalachian Engineered Floors, Inc.	Claims Services, Inc.
Applied Group Insurance Holdings, Inc.	Clayton Commercial Buildings, Inc.
Applied Investigations Inc.	Clayton Homes, Inc.
Applied Logisitics, Inc.	CMH Capital, Inc.
Applied Premium Finance, Inc.	CMH Hodgenville, Inc.
Applied Processing Center No. 60, Inc.	CMH Homes, Inc.
Applied Risk Services of New York, Inc.	CMH Manufacturing West, Inc.
Applied Risk Services, Inc.	CMH Manufacturing, Inc.
Applied Underwriters, Inc.	CMH of KY, Inc.
Ardent Risk Services	CMH Parks, Inc.
ARE Holding, LLC	CMH Services, Inc.
AU Captive Risk Assurance Co	CMH Set and Finish, Inc.
AU Captive Risk Assurance Co., Inc.	Cologne Services Corporation
AU Holding Company, Inc.	Columbia Insurance Company
AUI Employer Group No. 42, Inc.	Combined Claims Services, Inc.
Ben Bridge Jeweler, Inc.	Command Uniforms
Benjamin Moore & Co.	Commercial General Indemnity, Inc.
Berkshire Hathaway Credit Corp.	Commonwealth Uniforms Inc.
Berkshire Hathaway Finance Corporation	Continental Divide Insurance Co.
Berkshire Hathaway Inc. (Common Parent)	Continental Indemnity Company
Berkshire Hathaway Life Insurance Co. of NE	Cornhusker Casualty Company
Berksire Hathaway Assurance Company	CORT Business Services Corporation
BH Columbia Inc.	Coverage Dynamics Group, Inc.
BH Shoe Holdings, Inc.	Crescent Paint & Decorating Inc.
BHG Structured Settlements, Inc.	Criterion Insurance Agency
BHR Inc.	Cross Creek Apparel, LLC
BHSF, Inc.	Cross Creek Holdings, Inc
Blue Chip Stamps	Crowley Garment Mfg Co Inc.

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Berkshire Hathaway Inc. Sub-Group:

<p>Crowley Shirt Mfg Co Inc. CSI Life Insurance Company CTB Credit Corp. CTB International Corp. CTB IP, Inc. CTB MN Investments Co. Inc. CTB, Inc. Cumberland Asset Management, Inc. Cypress Insurance Company Dairy Queen Corporate Stores, Inc. Dairy Queen of Georgia, Inc. Delta Veneer Investors, LLC Denver Brick Company Dexter Shoe Company DQ Funding Corporation DQ Joint Venture Stores, Inc. DQ Managed Stores, Inc. DQ Wholly-Owned Stores, Inc. DQF, Inc. DQGC, Inc. Eastech Chemical Edmonds Material and Equipment Co. Elm Street Corporation Employers Insurance Services, Inc. Eureka Brick and Tile Company Executive Jet Europe, Inc. Executive Jet Management, Inc. Expertos, S.A. de C.V. Fairfield Insurance Co. Faraday Capital Limited Farriors, Inc. Fayette Cotton Mill, Inc. Finial Holdings, Inc. Finial Insurance, Inc. Finial Reinsurance Company First Berkshire Hathaway Life Insurance Company FlightSafety Capital Corp. FlightSafety China, Inc. FlightSafety Development, Inc. FlightSafety International Inc. FlightSafety New York, Inc. FlightSafety Properties, Inc. FlightSafety Services Corporation FlightSafety Texas, Inc. Floors Inc. Footwear Investment Company Forest River Financial Services, Inc. Forest River Housing, Inc. Forest River Warranty Company Forest River, Inc. France/Scott Fetzer Company Freedom Warehouse Corp.</p>	<p>Fruit of the Loom Caribbean, Inc. Fruit of the Loom Texas, Inc. Fruit of the Loom Trading Company Fruit of the Loom, Inc. Fruit of the Loom, Inc. FSI Delaware Holding Corp. FTL Regional Sales Co., Inc. FTL Sales Company, Inc. Garan Central America Corp. Garan Incorporated Garan Manufacturing Corp Garan Services Corp Gateway Underwriters Agency, Inc. GEICO Casualty Company GEICO Corporation GEICO General Insurance Company GEICO Indemnity Company GEICO Products, Inc. Gen Re Capital Consultants, Inc. f/k/a General Re Gen Re Intermediaries Corporation General Re Assets Investment (I), Inc. General Re Corporate Finance, Inc. General Re Corporation General Re Financial Products Corporation General Re Funding Corporation General Re Investment Holdings Corporation General Re New England Asset Management General Re Services Corporation General Reinsurance Corporation General Star Indemnity Company General Star Management Company General Star National Insurance Company Genesis Indemnity Insurance Company Genesis Insurance Company Genesis Professional Liability Underwriters Genesis Underwriting Management Company GenRe Gisbourne LLC Giles Industries, Inc. GMK, Ltd. Golden Skillet International, Inc. Government Employees Financial Corporation Government Employees Insurance Company GRD Corporation GRD Global, Inc. GRD Holdings Corporation Griffey Uniforms H.H.Brown Shoe Company, Inc. H.H.Brown Shoe Technologies, Inc. H.J. Justin and Sons, Inc. Halex/Scott Fetzer Company Hall of Fame Paint Supply Inc. Hardy Frames, Inc.</p>
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Harris Uniforms
Harrison Uniforms
HDS Redevelopment Corporation
Helzberg's Diamond Shops, Inc.
Henley Holdings, LLC
Homefirst Agency, Inc.
Homemakers Plaza, Inc.
Indecor Group Inc. d/b/a J.C.Licht Company
Innovative Building Products, Inc.
Insurance Counselors of Nevada, Inc.
Insurance Counselors, Inc.
International Dairy Queen, Inc.
International Insurance Underwriters, Inc.
Isabela Shoe Corporation
J. S. Justin, Inc.
Janovic/Plaza Inc.
JM Contracting Services, Inc.
Johns Manville China, LTD.
Johns Manville Corporation
Johns Manville, Inc.
Jordan's Furniture, Inc.
Justin Belt Company, Inc.
Justin Boot Company
Justin Brands, Inc.
Justin Industries, Inc.
Justin Royalty BV
Kale Uniforms
Kansas Bankers Surety Company
Karmelkorn Shoppes, Inc.
Kay Uniforms
Kleberg Holdings, Inc.
LA Terminals
Leesburg Yarn Mills, Inc.
M & C Products, Inc.
Macro Retailing, Inc.
Mapletree Transportation, Inc.
MarineSafety International, Inc.
Martin Manufacturing Company
Martin Mills, Inc.
Maryland Ventures, Inc.
McCain Uniform Company Inc.
McCarty-Hull Cigar Company, Inc.
McLane Company, Inc.
McLane Eastern, Inc.
McLane Express, Inc.
McLane Foodservice, Inc.
McLane Mid-Atlantic, Inc.
McLane Minnesota, Inc.
McLane New Jersey, Inc.
McLane Southern, Inc.
McLane Suneast, Inc.
McLane Western, Inc.

McLane Midwest, Inc.
Medical Protective Corporation
Medical Protective Finance Corporation
Medical Protective Insurance Services, Inc.
Metro Uniforms
MH Transport, Inc.
MiTek Framings, Inc.
MiTek Holdings, Inc.
MiTek Industries, Inc.
MiTek, Inc.
MMX Corporation
Mobile Disaster Structures, Inc.
Mossy Oak Apparel Company
Mount Vernon Fire Insurance Company
Mountain View Marketing, Inc.
Mouser Electronics, Inc.
MS Property Company
MT Sub, Inc.
National Fire & Marine Insurance Co.
National Indemnity Company
National Indemnity Company of Mid-America
National Indemnity Company of the South
National Liability & Fire Insurance Co.
National Reinsurance Corporation
Nationwide Uniforms
Nebraska Furniture Mart, Inc.
NetJets Aviation Inc.
NetJets Europe Holdings LLC
NetJets Inc.
NetJets International Inc.
NetJets Large Aircraft, Inc.
NetJets Leasing, Inc.
NetJets M E Inc.
NetJets Sales Inc.
NetJets Services Inc.
NetJets U.S., Inc.
NFM of Kansas, Inc.
Nick Bloom Uniforms
NJ Executive Services Inc.
NJA Jets Inc.
NJE Holdings LLC
NJI Sales Inc.
NJI, Inc.
Nocona Boot Company
North American Casualty Co
North Star Reinsurance Corporation
North Star Syndicate, Inc.
Northern States Agency, Inc.
Northland/Scott Fetzer Company
Oak River Insurance Company
OBH Inc.
OCSAP, Ltd.

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PacifiCorp			
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Berkshire Hathaway Inc. Sub-Group:

Old City Paint & Decorating, Inc.
Orange Julius of America
Paint Rental Associates Inc.
Pan-Am Shoe Co., Inc.
Pennsylvania Reinsurance Company
Pima Uniforms
Pinnacle Paint & Decorating, Inc.
Plaza Financial Services Co.
Plaza Paint & Decorating Centers Inc.
Plaza Resources Co.
Ponce Fashions, Inc.
Portland Gold Corp. d/b/a/ Maine Paint Service
Precision Brand Products
Precision Steel Warehouse - Charlotte
Precision Steel Warehouse - Franklin Park
Priority One Financial Services, Inc.
Pro Installations, Inc.
Professional Datasolutions, Inc.
Promesa Health, Inc.
Queen Carpet Corporation
R.C.Willey Home Furnishings
Rabun Apparel, Inc.
Rainbow State Paint & Decorating Inc.
Redwood Fire and Casualty Insurance Co.
RENTCO Trailer Corporation
Republic Insurance Company
Resolute Management Inc.
Richline Group, Inc.
Ringwalt & Liesche Co
Rintel Properties, Inc.
Robert f. deCastro Inc.
Roberts Men's Shop
Running with Heels
Russell Asset Management, Inc.
Russell Corporation
Russell Financial Services, Inc.
Russell Servicing Company, Inc.
Salado Sales, Inc.
Salt Lake Paint
Scott Fetzer Financial Group, Inc.
ScottCare Corporation
Seattle Paint Supply, Inc.
Seaworthy Insurance Company
See's Candies, Inc.
See's Candy Shops, Inc.
Seventeenth Street Realty, Inc.
Shaw Contract Flooring Installation Services, Inc.
Shaw Contract Flooring Services, Inc.
Shaw Diversified Services, Inc.
Shaw Floors, Inc.
Shaw Funding Company
Shaw Industries Group, Inc.

Shaw Industries, Inc.
Shaw International Services, Inc. (fka Shaw Financial)
Shaw Retail Properties, Inc.
Shaw Transport, Inc.
SHX Flooring, Inc.
SHX Leasing, Inc.
Silver State Uniforms
Simon's Incorporated
Soco West
Sofft Shoe Company, Inc.
Sol Frank Uniforms Inc.
Somerset Services
Southern Energy Homes of North Carolina, Inc.
Southern Energy Homes of Pennsylvania, Inc.
Southern Energy Homes Retail Corp.
Southern Energy Homes, Inc.
Southwest Paint & Decorating Inc.
Stahl/Scott Fetzer Company
Standard Plywoods, Inc.
Star Furniture Company
Stonyridge Trust
Strategic Staff Management, Inc.
Strick Mexicana, S.A.
Technical Coatings Co.
The Ben Bridge Corporation
The BVD Licensing Corp.
The Eagle Company
The Fechheimer Brothers Co.
The Indecor Group, Inc.
The Koskovich Company, Inc.
The Medical Protective Company
The Pampered Chef North America, Ltd
The Pampered Chef, Ltd
The Scott Fetzer Company
Tony Lama Company
Top Five Club, Inc.
TPC - European Holdings, Ltd.
Transco, Inc.
TTI, Inc.
TTI, Inc.
U.S. Investment Corporation
U.S. Liability Insurance Company
U.S. Underwriters Insurance Company
Undergarment Fashions, Inc.
Unified Supply Chain, Inc.
Uniforms of Texas
Union Sales, Inc.
Union Underwear Co., Inc.
Unione Italiana Reinsurance Company of America, Inc.
United Consumer Financial Services, Inc.
United Direct Finance Inc.
United States Aviation Underwriters, Inc.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
PacifiCorp			
FOOTNOTE DATA			

Berkshire Hathaway Inc. Sub-Group:

Universal Uniforms
 Vanderbilt ABS Corp.
 Vanderbilt Mortgage & Finance, Inc.
 Vanderbilt Property & Casualty Insurance Co., Ltd.
 Vanderbilt SPC, Inc.
 Vanity Fair Brands, Inc.
 Vanity Fair Inc.
 Vanity Fair Ventures, Inc.
 Veritas Insurance Group, Inc.
 Vessel Assist Association of America, Inc.
 Vessel Assist Insurance Services, Inc.
 VFI Credit Corporation
 VFI-Mexico, Inc.
 Virginia Paint Co., Inc.
 Vision Retailing
 Walterboro Veneer Company, Inc.
 Wayne/Scott Fetzer Company
 Waynesburg Shirt Company Inc.
 Wenco Financial, Inc.
 Wesco Financial Corporation
 Wesco Holdings Midwest, Inc.
 Wesco-Financial Insurance Co.
 West Virginia Uniforms
 Western/Scott Fetzer Company
 Wheeler Brick Company, Inc.
 Whittaker, Clark & Daniels
 Witt Brick & Supply, Inc.
 WMC Corp.
 Woodperfect, Inc.
 World Book Encyclopedia, Inc.
 World Book, Inc.
 World Book/Scott Fetzer Company, Inc.
 Worldbook.com Inc.
 X-L-CO., Inc.
 XLI, inc.
 XTR, Inc.
 XTRA Chassis, Inc.
 XTRA Companies, Inc.
 XTRA Corporation
 XTRA Finance Corporation
 XTRA Intermodal, Inc.
 XTRA International Pacific, LTD.
 XTRA International, LTD.
 XTRA Mexicana, S.A. de C.V.
 Zuckerbergs Uniforms

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	Federal:					
2	Income		38,948,947	144,551,840	132,785,096	3,854,556
3	FICA	352,142	24,571	32,848,762	32,850,336	
4	Unemployment	1,172		371,625	361,556	
5	Unemployment - Energy	47,848		182,451	100,790	
6	Unemployment - Interwest	257		1,721	1,870	
7	Excise Tax - Coal	132,490		4,070,046	4,117,778	
8	Subtotal	533,909	38,973,518	182,026,445	170,217,426	3,854,556
9						
10	State:					
11						
12	Arizona:					
13	Property	945,168		1,954,321	1,922,329	
14	Income		514,721	317,480	378,905	19,863
15	Subtotal	945,168	514,721	2,271,801	2,301,234	19,863
16						
17	California:					
18	Property			1,850,687	1,850,687	
19	Unemployment	1,392		23,536	24,608	
20	Franchise-Income		-84,848	651,561	815,585	40,766
21	Regulatory Commission			4,843	4,843	
22	Use	48,379		199,695	199,286	
23	Local Franchise	677,131		978,966	906,262	
24	Subtotal	726,902	-84,848	3,709,288	3,801,271	40,766
25						
26	Colorado:					
27	Property	1,752,000		1,776,603	1,768,603	
28	Income		314,924	153,909	1,581	9,629
29	Subtotal	1,752,000	314,924	1,930,512	1,770,184	9,629
30						
31	Idaho:					
32	Property	1,468,966		2,470,100	2,455,109	
33	Income		168,626	1,231,112	1,295,026	77,028
34	KWh	500		20,960	20,960	
35	Unemployment	1,901		34,007	34,912	
36	Regulatory Commission			347,005	347,005	
37	Use	25,986		217,289	239,435	
38	Subtotal	1,497,353	168,626	4,320,473	4,392,447	77,028
39						
40	Montana:					
41	TOTAL	21,123,323	51,795,841	320,614,257	309,517,839	4,123,743

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
	31,036,759	125,610,768			18,941,072	2
365,997	40,000				32,848,762	3
11,241					371,625	4
129,509					182,451	5
108					1,721	6
84,758					4,070,046	7
591,613	31,076,759	125,610,768			56,415,677	8
						9
						10
						11
						12
977,160		1,954,321				13
	596,009	272,577			44,903	14
977,160	596,009	2,226,898			44,903	15
						16
						17
		1,825,141			25,546	18
320					23,536	19
	119,942	559,406			92,155	20
					4,843	21
48,788					199,695	22
749,835		978,966				23
798,943	119,942	3,363,513			345,775	24
						25
						26
1,760,000		1,775,929			674	27
	172,225	132,141			21,768	28
1,760,000	172,225	1,908,070			22,442	29
						30
						31
1,483,957		2,467,206			2,894	32
	309,568	1,056,987			174,125	33
500		20,960				34
996					34,007	35
					847,005	36
3,840					217,289	37
1,489,293	309,568	3,545,153			775,320	38
						39
						40
20,901,699	44,601,542	242,707,061			77,907,196	41

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4	
TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR						
<p>1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.</p> <p>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.</p> <p>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.</p> <p>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.</p>						
Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	Property	1,263,200		2,387,678	2,458,521	
2	Corporate License-Income		301,026	158,956	169,397	9,946
3	Energy License	58,459		231,921	227,704	
4	Wholesale Energy	40,679		166,221	162,243	
5	Subtotal	1,362,338	301,026	2,944,776	3,017,865	9,946
6						
7						
8	New Mexico:					
9	Property	5,397		11,031	10,912	
10	Income			966	982	60
11	Subtotal	5,397		11,997	11,894	60
12						
13	Oregon:					
14	Property		8,111,050	15,956,889	15,730,982	
15	Unemployment	29,010		967,978	957,119	
16	Wilsonville Payroll	649		1,117	1,397	
17	Regulatory Commission			2,502,769	2,502,769	
18	Excise-Income		-953,134	7,930,158	6,658,111	496,168
19	City of Portland-Income		101,633	6,344	3,000	397
20	Office of Energy		203,569	489,288	571,438	
21	Tri-Met	361,336		791,304	812,380	
22	Lane County			3,081	3,081	
23	Franchise	2,805,400		20,426,637	19,432,148	
24	Subtotal	3,196,395	7,463,118	49,075,565	46,672,425	496,565
25						
26						
27	Utah:					
28	Property	288,593		34,140,315	34,100,492	
29	Income		4,144,756	7,746,091	9,450,228	484,651
30	Unemployment	17,668		350,330	353,930	
31	Regulatory Commission			3,556,709	3,556,709	
32	Navajo Nation			7,345	7,345	
33	Use	297,291		3,332,673	3,356,406	
34	Gross Receipts	2,464,802			2,464,802	
35	Subtotal	3,068,354	4,144,756	49,133,463	53,289,912	484,651
36						
37	Washington:					
38	Property	3,350,000		4,258,589	3,308,589	
39	Unemployment	1,956		72,796	71,287	
40	Business & Occupation	3,072		9,174	7,384	
41	TOTAL	21,123,323	51,795,841	320,614,257	309,517,839	4,123,743

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4	
TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)						
<p>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).</p> <p>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.</p> <p>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.</p> <p>8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.</p> <p>9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.</p>						
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)	
1,192,357		2,387,678				1
	321,413	136,474			22,482	2
62,676		231,921				3
44,657		166,221				4
1,299,690	321,413	2,922,294			22,482	5
						6
						7
						8
5,516		11,031				9
	76	828			138	10
5,516	76	11,859			138	11
						12
						13
4,121	7,889,264	15,862,312			94,577	14
39,869					967,978	15
369					1,117	16
					2,502,769	17
	-1,729,013	6,808,539			1,121,619	18
	98,686	5,447			897	19
	285,719	489,288				20
340,260					791,304	21
					3,081	22
3,799,889		20,426,637				23
4,184,508	6,544,656	43,592,223			5,483,342	24
						25
						26
						27
328,416		31,081,518			3,058,797	28
	6,333,544	6,650,506			1,095,585	29
14,068					350,330	30
					3,556,709	31
		7,345				32
273,558					3,332,673	33
						34
616,042	6,333,544	37,739,369			11,394,094	35
						36
						37
4,300,000		4,146,198			112,391	38
3,465					72,796	39
4,862		9,174				40
20,901,699	44,601,542	242,707,061			77,907,196	41

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	Public Utility	720,226		8,666,551	8,530,364	
2	Regulatory Commission			430,443	430,443	
3	Use	31,611		614,373	606,260	
4	Retailing	29		156	156	
5	Land Tax			58	58	
6	Subtotal	4,106,894		14,052,140	12,954,541	
7						
8	Washington D.C.:					
9	Unemployment					
10	Franchise-Income			747	-2,582	47
11	Subtotal			747	-2,582	47
12						
13	Wyoming:					
14	Property	3,582,241		7,326,653	7,243,529	
15	Property - Glenrock					
16	Unemployment	2,448		134,398	133,772	
17	Other Payroll Taxes			141	141	
18	Regulatory Commission			891,463	891,463	
19	Franchise	187,800		1,343,369	1,330,869	
20	Use	139,672		1,126,859	1,188,746	
21	Annual Report			35,319	35,319	
22	Subtotal	3,912,161		10,858,202	10,823,839	
23						
24	State Other					-869,368
25						
26	Miscellaneous:					
27	Goshute Possessory					
28	Sho-Ban Possessory			131,599	131,599	
29	Navajo Possessory	16,452		33,746	33,325	
30	Ute Possessory			9,543	9,543	
31	Crow Possessory			59,130	59,130	
32	Umatilla			50,615	50,615	
33	Other Taxes			-5,785	-16,829	
34	Subtotal	16,452		278,848	267,383	-869,368
35						
36						
37						
38						
39						
40						
41	TOTAL	21,123,323	51,795,841	320,614,257	309,517,839	4,123,743

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4	
TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)						
<p>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).</p> <p>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.</p> <p>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.</p> <p>8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.</p> <p>9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.</p>						
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)	
856,413		8,666,551				1
					430,443	2
39,724					614,373	3
29		156				4
		58				5
5,204,493		12,822,137			1,230,003	6
						7
						8
						9
	-3,282	641			106	10
	-3,282	641			106	11
						12
						13
3,665,365		7,306,459			20,194	14
						15
3,074					134,398	16
		141				17
					891,463	18
200,300		1,343,369				19
77,785					1,126,859	20
		35,319				21
3,946,524		8,685,288			2,172,914	22
						23
	-869,368					24
						25
						26
						27
		131,599				28
16,873		33,746				29
		9,543				30
		59,130				31
		50,615				32
11,044		-5,785				33
27,917	-869,368	278,848				34
						35
						36
						37
						38
						39
						40
20,901,699	44,601,542	242,707,061			77,907,196	41

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

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

Federal Income Tax - Other Income & Deductions - 409.2

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

Payroll taxes are charged to functional accounts, which is consistent with where labor is charged.

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

Payroll taxes are charged to functional accounts, which is consistent with where labor is charged.

Schedule Page: 262 Line No.: 5 Column: I

Various Operations and Maintenance Accounts.

Schedule Page: 262 Line No.: 6 Column: I

Various Operations and Maintenance Accounts.

Schedule Page: 262 Line No.: 7 Column: I

Fuel Inventory - 151

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

State Income Tax - Other Income & Deductions - 409.2

Schedule Page: 262 Line No.: 18 Column: I

Account

Taxes Applicable to Other Income and Deductions- 408.2, 409.2 \$ 23,797

Distribution Rent Expense, Rents - 589 1,749

Total \$ 25,546

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

Various Operations and Maintenance Accounts.

Schedule Page: 262 Line No.: 20 Column: I

State Income Tax - Other Income & Deductions - 409.2

Schedule Page: 262 Line No.: 21 Column: I

Regulatory Commission Expense Account - 928

Schedule Page: 262 Line No.: 22 Column: I

Clearing Account - 184

Schedule Page: 262 Line No.: 27 Column: I

Taxes Applicable to Other Income and Deductions- 408.2, 409.2

Schedule Page: 262 Line No.: 28 Column: I

State Income Tax - Other Income & Deductions - 409.2

Schedule Page: 262 Line No.: 32 Column: I

Taxes Applicable to Other Income And Deductions - 408.2, 409.2

Schedule Page: 262 Line No.: 33 Column: I

State Income Tax - Other Income & Deductions - 409.2

Schedule Page: 262 Line No.: 35 Column: I

Various Operations and Maintenance Accounts.

Schedule Page: 262 Line No.: 36 Column: I

Regulatory Commission Expense Account - 928

Schedule Page: 262 Line No.: 37 Column: I

Clearing Account - 184

Schedule Page: 262.1 Line No.: 2 Column: I

State Income Tax - Other Income & Deductions - 409.2

Schedule Page: 262.1 Line No.: 10 Column: I

State Income Tax - Other Income & Deductions - 409.2

Schedule Page: 262.1 Line No.: 14 Column: I

Account

Taxes Applicable to Other Income and Deductions- 408.2, 409.2 \$ 45,121

Distribution Rent Expense, Rents - 589 49,456

Total \$ 94,577

Schedule Page: 262.1 Line No.: 15 Column: I

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Various Operations and Maintenance Accounts.

Schedule Page: 262.1 Line No.: 16 Column: I

Various Operations and Maintenance Accounts.

Schedule Page: 262.1 Line No.: 17 Column: I

Regulatory Commission Expense Account - 928

Schedule Page: 262.1 Line No.: 18 Column: I

State Income Tax - Other Income & Deductions - 409.2

Schedule Page: 262.1 Line No.: 19 Column: I

State Income Tax - Other Income & Deductions - 409.2

Schedule Page: 262.1 Line No.: 21 Column: I

Various Operations and Maintenance Accounts.

Schedule Page: 262.1 Line No.: 22 Column: I

Various Operations and Maintenance Accounts.

Schedule Page: 262.1 Line No.: 28 Column: I

	Account	
Taxes Applicable to Other Income and Deductions-	408.2, 409.2	\$ 14,400
Construction-	107	1,984,418
Fuel Stock -	151	83,054
Operating and Maintenance Expense -	401,402	976,925
Total		\$ 3,058,797

Schedule Page: 262.1 Line No.: 29 Column: I

State Income Tax - Other Income & Deductions - 409.2

Schedule Page: 262.1 Line No.: 30 Column: I

Various Operations and Maintenance Accounts.

Schedule Page: 262.1 Line No.: 31 Column: I

Regulatory Commission Expense Account - 928

Schedule Page: 262.1 Line No.: 33 Column: I

Clearing Account - 184

Schedule Page: 262.1 Line No.: 38 Column: I

	Account	
Taxes Applicable to Other Income and Deductions-	408.2, 409.2	\$ 109,130
Distribution Rent Expense, Rents -	589	3,261
Total		\$ 112,391

Schedule Page: 262.1 Line No.: 39 Column: I

Various Operations and Maintenance Accounts.

Schedule Page: 262.2 Line No.: 2 Column: I

Regulatory Commission Expense Account - 928

Schedule Page: 262.2 Line No.: 3 Column: I

Clearing Account - 184

Schedule Page: 262.2 Line No.: 10 Column: I

State Income Tax - Other Income & Deductions - 409.2

Schedule Page: 262.2 Line No.: 14 Column: I

	Account	
Taxes Applicable to Other Income and Deductions-	408.2, 409.2	\$ 16,610
Distribution Rent Expense, Rents -	589	3,584
Total		\$ 20,194

Schedule Page: 262.2 Line No.: 16 Column: I

Various Operations and Maintenance Accounts.

Schedule Page: 262.2 Line No.: 18 Column: I

Regulatory Commission Expense Account - 928

Schedule Page: 262.2 Line No.: 20 Column: I

Clearing Account - 184

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/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%						
3	4%						
4	7%						
5	10%	46,407,861			411.4	5,789,424	
6					420	1,624,452	12,167,578
7	Idaho	908,765			411.4	65,436	
8	TOTAL	47,316,626				7,479,312	12,167,578
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13	10%	14,371,314			420	440,808	-12,167,578
14							
15	Total Nonutility	14,371,314				440,808	-12,167,578
16							
17							
18							
19							
20							
21							
22							
23							
24							
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Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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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
			2
			3
			4
40,618,437	30/35		5
10,543,126			6
843,329			7
52,004,892			8
			9
			10
			11
			12
1,762,928	32		13
			14
1,762,928			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
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Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

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

46(f)2

Schedule Page: 266 Line No.: 6 Column: e

46(f)1

Schedule Page: 266 Line No.: 6 Column: g

Reclass from Non-Utility

Schedule Page: 266 Line No.: 13 Column: g

Reclass to Utility



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(Next Page is 269)

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4	
OTHER DEFERRED CREDITS (Account 253)						
1. Report below the particulars (details) called for concerning other deferred credits.						
2. For any deferred credit being amortized, show the period of amortization.						
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than \$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		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Cogeneration Bonds - Sunnyside	413,417				413,417
2						
3	Working Capital Deposit DG&T	1,253,297			290,847	1,544,144
4						
5	Working Capital and Coal Pile					
6	Deposits from Provo City	273,000				273,000
7						
8	Working capital deposit from UAMPS	245,000			306,000	551,000
9						
10	Reclamation Costs - Trapper Mine	3,766,482			270,977	4,037,459
11						
12	Reclamation Costs - Deseret Mine	554,643	131	6,601		548,042
13						
14	Reclamation Costs - Trail					
15	Mountain Mine	1,146,738	131	15,200		1,131,538
16						
17	Deferred Compensation - PPL	2,479,606	124	748,537	118,824	1,849,893
18						
19	Transmission Service Deposit	1,631,948		335,948	11,859,600	13,155,600
20						
21	Def. Credits - Rights of Way	4,189	567	4,189	230,000	230,000
22						
23	MCI F.O.G. wire lease	558,678	454	3,351,021	3,350,811	558,468
24						
25	Redding Contract (20)	4,950,064	456	549,996		4,400,068
26						
27	Foote Creek Contract (15)	1,118,222	142	137,640		980,582
28						
29	Environmental Liabilities -					
30	Centralia Plant	154,830	506	117,571	61,058	98,317
31						
32	Environmental Liabilities -					
33	Centralia Mine	3,227,248	506.3	4,143	102,550	3,325,655
34						
35	Wyoming Joint Powers Water					
36	Board Settlement (7)	975,000	232	300,000		675,000
37						
38						
39	Unearned Joint Use Pole Contract	3,520,283	454	8,584,662	8,641,728	3,577,349
40						
41	Oregon DSM Loans NPV Unearned	1,688,955	456	272,465		1,416,490
42						
43	Exec Trust Comp Reduction Plan	15,992,639	124	7,177,250	1,421,098	10,236,487
44						
45	Miscellaneous Security Deposits	23,012				23,012
46						
47	TOTAL	61,791,513		37,332,379	35,068,828	59,527,962

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4	
OTHER DEFERRED CREDITS (Account 253)						
1. Report below the particulars (details) called for concerning other deferred credits.						
2. For any deferred credit being amortized, show the period of amortization.						
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than \$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		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Environmental Liabilities -					
2	Non-Current	9,631,750	182.3	8,502,461	1,319,884	2,449,173
3						
4	Deseret Power Security Deposits	535,725			24,530	560,255
5						
6	Deferred Revenue -					
7	Lease Incentives (10)	358,395	931	62,756		295,639
8						
9	Other Deferred Credits - C&T	2,739,745		4,177,961	5,345,129	3,906,913
10						
11						
12	Software License Payments	1,064,748	560	532,374		532,374
13						
14	Deferred Revenue -					
15	Duke/Hermiston Gas Settlement (5)	3,428,226		754,839		2,673,387
16						
17	Other Deferred Credits	55,673	557	194,565	163,392	24,500
18						
19	Emission Allowance Sales Proceeds		411.8	1,502,200	1,503,600	1,400
20						
21	Mill Fork Lease Bonus Payment				58,800	58,800
22						
23						
24						
25						
26						
27						
28						
29						
30						
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32						
33						
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35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	61,791,513		37,332,379	35,068,828	59,527,962

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 269 Line No.: 19 Column: c

Accounts
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Schedule Page: 269.1 Line No.: 9 Column: c

Accounts
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Schedule Page: 269.1 Line No.: 15 Column: c

Accounts
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Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/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 relating to amortizable property.					
2. For other (Specify), include deferrals relating to other income and deductions.					
Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	
1	Accelerated Amortization (Account 281)				
2	Electric				
3	Defense Facilities	300,173		300,173	
4	Pollution Control Facilities				
5	Other (provide details in footnote):				
6					
7					
8	TOTAL Electric (Enter Total of lines 3 thru 7)	300,173		300,173	
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)	300,173		300,173	
18	Classification of TOTAL				
19	Federal Income Tax	264,262		264,262	
20	State Income Tax	35,911		35,911	
21	Local Income Tax				

NOTES

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4		
ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)							
3. Use footnotes as required.							
CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
							3
							4
							5
							6
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NOTES (Continued)

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	1,548,668,566	321,698,216	264,607,293
3	Gas			
4	FAS 109 Regulatory Asset	464,097,261	620,143	
5	TOTAL (Enter Total of lines 2 thru 4)	2,012,765,827	322,318,359	264,607,293
6	Nonutility	-7,192,561		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	2,005,573,266	322,318,359	264,607,293
10	Classification of TOTAL			
11	Federal Income Tax	1,765,650,665	283,760,077	232,952,867
12	State Income Tax	239,922,601	38,558,282	31,654,426
13	Local Income Tax			

NOTES

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
			390,958,495		156,308,280	1,371,109,274	2
							3
		182	5,551,770			459,165,634	4
			396,510,265		156,308,280	1,830,274,908	5
1,253,060	2,124,776			282	10,679,426	2,615,149	6
							7
							8
1,253,060	2,124,776		396,510,265		166,987,706	1,832,890,057	9
							10
1,103,159	1,870,593		349,076,558		147,011,311	1,613,625,194	11
149,901	254,183		47,433,707		19,976,395	219,264,863	12
							13

NOTES (Continued)

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

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

Accounts

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

Accounts

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Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)					
1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.					
2. For other (Specify), include deferrals relating to other income and deductions.					
Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	
1	Account 283				
2	Electric				
3	Regulatory Assets	257,084,452	23,381,893	33,687,074	
4					
5	Deriv. Contracts Reg. Assets	102,936,510			
6					
7	Other Deferred Liabilities	67,495,032	10,749,724	30,409,325	
8					
9	TOTAL Electric (Total of lines 3 thru 8)	427,515,994	34,131,617	64,096,399	
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)	427,515,994	34,131,617	64,096,399	
20	Classification of TOTAL				
21	Federal Income Tax	376,372,094	30,048,522	56,428,679	
22	State Income Tax	51,143,900	4,083,095	7,667,720	
23	Local Income Tax				

NOTES

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

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

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
		190	204,452,859	190	89,930,754	132,257,166	3
							4
*****	22,479,675	283	14,458,849	283	1	97,163,581	5
							6
*****	14,458,849		55,944,360		77,403,764	64,648,624	7
							8
*****	36,938,524		274,856,068		167,334,519	294,069,371	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
*****	36,938,524		274,856,068		167,334,519	294,069,371	19
							20
*****	32,519,644		241,975,602		147,316,635	258,889,416	21
*****	4,418,880		32,880,466		20,017,884	35,179,955	22
							23

NOTES (Continued)

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

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

Accounts

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

Accounts

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Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/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 Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	FAS 109 Regulatory Liability	25,544,625	190	3,157,404		22,387,221
2	FAS 109 - WA Flow Through	22,341,215	190	8,942,178		13,399,037
3	OR Gain on Sales of Assets	163,768			13,875	177,643
4	Property Insurance Reserve	2,233,114	228,924	2,233,114		
5	SMUD Revenue Imputation (11)	28,026,746	440,442	4,898,042	2,333,609	25,462,313
6	Oregon Rate Refund	79,971	142	5		79,966
7	Utah Home Energy Lifeline	(8,486)	142	2,295,469	2,451,498	147,543
8	BPA Washington Balancing Account	2,329,355	440,442	3,358,488	1,029,133	
9	BPA Oregon Balancing Account	13,850,191	440,442	14,306,592	456,401	
10	BPA Idaho Balancing Account	7,913,580	440,442	9,047,358	1,133,778	
11	ARO/ Reg Difference - Deer Creek Mine Reclamation	461,450	230	167,611	203,338	497,177
12	ARO/Reg Difference - Trojan Nuclear Plant	833,787	230	117,057	149,083	865,813
13	Reg Liability - WA West Valley Lease Reduction	342,758	440,442,431	576,383	233,625	
14	Reg Liability - CA West Valley Lease Red (3)	78,145	440,442	29,510	5,642	54,277
15	Reg Liability - ID West Valley Lease Red (3)	274,125			382,653	656,778
16	Reg Liability - WY West Valley Lease Reduction	608,494			848,460	1,456,954
17	Reg Liability - UT West Valley Lease Red (1.5)	1,364,461	440,442	1,021,134	74,843	418,170
18	Reg Liability - A&G Credit - WA (1)	385,804	440,442	251,998	294,435	428,241
19	Reg Liability - A&G Credit - CA (3)	125,169	440,442	47,268	9,037	86,938
20	Reg Liability - A&G Credit ID (3)	277,319			399,549	676,868
21	Reg Liability - A&G Credit WY	619,940			890,855	1,510,795
22	Washington Low Income Program	(68,874)	142	769,010	795,920	-41,964
23	Reg Liability - OR Consolidation	115,624	456	468,074		-352,450
24	Reg Liability - Blue Sky - OR				462,671	462,671
25	Reg Liability - Blue Sky - WA				81,041	81,041
26	Reg Liability - Blue Sky - CA				34,975	34,975
27	Reg Liability - Blue Sky - UT				589,668	589,668
28	Reg Liability - Blue Sky - ID		232	11,854	31,831	19,977
29	Reg Liability - Blue Sky - WY				104,551	104,551
30	Reg Liability - ID Irrigation		142	450,000	450,000	
31	Reg Liability - Reclass	2,090,629			48,603	2,139,232
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	109,982,910		52,148,549	13,509,074	71,343,435

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 278 Line No.: 31 Column: f

The following is a reconciliation of the regulatory liability reclassification account:

	YTD
	<u>December 31, 2007</u>
Reclassified from Regulatory Assets to Regulatory Liabilities:	
California DSM Regulatory Asset	\$ 248,987
Washington DSM Regulatory Asset	1,095,675
Utah DSM Regulatory Asset	400,156
Reclassified from Regulatory Liabilities to Regulatory Assets:	
Washington Low Income Program	41,964
Regulatory Liability Oregon Consolidated	<u>352,450</u>
	\$ 2,139,232

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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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	1,263,790,936	1,065,628,795
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,014,421,434	917,467,966
5	Large (or Ind.) (See Instr. 4)	914,316,590	828,823,262
6	(444) Public Street and Highway Lighting	18,902,690	18,427,832
7	(445) Other Sales to Public Authorities	17,509,459	16,659,617
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	3,228,941,109	2,847,007,472
11	(447) Sales for Resale	856,864,831	750,904,692
12	TOTAL Sales of Electricity	4,085,805,940	3,597,912,164
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	4,085,805,940	3,597,912,164
15	Other Operating Revenues		
16	(450) Forfeited Discounts	6,784,670	5,910,738
17	(451) Miscellaneous Service Revenues	7,215,245	6,288,827
18	(453) Sales of Water and Water Power	107,480	15,228
19	(454) Rent from Electric Property	18,760,759	19,392,877
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	68,728,424	76,514,879
22	(456.1) Revenues from Transmission of Electricity of Others	56,223,453	41,246,494
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	157,820,031	149,369,043
27	TOTAL Electric Operating Revenues	4,243,625,971	3,747,281,207

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
ELECTRIC OPERATING REVENUES (Account 400)					
<p>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.)</p> <p>6. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.</p> <p>7. For Lines 2,4,5, and 6, see Page 304 for amounts relating to unbilled revenue by accounts.</p> <p>8. Include unmetered sales. Provide details of such Sales in a footnote.</p>					
MEGAWATT HOURS SOLD				AVG.NO. CUSTOMERS PER MONTH	
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	Line No.	
				1	
15,975,228	15,334,601	1,440,688	1,411,602	2	
				3	
15,951,322	15,397,126	204,569	199,474	4	
20,892,453	20,471,544	34,119	34,099	5	
136,080	149,401	4,230	4,258	6	
435,395	444,665	13	14	7	
				8	
				9	
53,390,478	51,797,337	1,683,619	1,649,447	10	
13,723,856	13,656,537			11	
67,114,334	65,453,874	1,683,619	1,649,447	12	
				13	
67,114,334	65,453,874	1,683,619	1,649,447	14	

Line 12, column (b) includes \$ 192,299,000 of unbilled revenues.

Line 12, column (d) includes 3,315,584 MWH relating to unbilled revenues

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 300 Line No.: 11 Column: f

For a complete list of the number of customers see pages 310-311 Sales for Resale of this Form No. 1.

Schedule Page: 300 Line No.: 11 Column: g

For a complete list of the number of customers see pages 310-311 Sales for Resale of this Form No. 1.

Schedule Page: 300 Line No.: 27 Column: b

	Page 300 Year ended December 31, 2007	Page 304 Year ended December 31, 2007	Variance Year ended December 31, 2007
Sales of Electricity			
Residential Sales - Account (440)	\$ 1,263,790,936	\$ 1,263,790,936	\$ -
Commercial and Industrial Sales - Account (442)			
Small (Commercial)	1,014,421,434	1,014,421,434	-
Large (Industrial)	914,316,590	914,316,590	- (a)
Public Street and Highway Lighting - Account (444)	18,902,690	18,902,690	-
Other Sales to Public Authorities - Account (445)	17,509,459	17,509,459	-
Sales to Railroads and Railways - Account (446)	-	-	-
Interdepartmental Sales - Account (448)	-	-	-
Total Sales to Ultimate Consumers	3,228,941,109	3,228,941,109	-
 Sales for Resale - Account (447)	856,864,831	-	856,864,831 (b)
Total Sales of Electricity	4,085,805,940	3,228,941,109	856,864,831
 (less) Provision for Rate Refunds - Account (449.1)	-	-	-
Total Revenues Net of Provisions for Refunds	4,085,805,940	3,228,941,109	856,864,831
 Other Operating Revenues			
Forfeited Discounts - Account (450)	6,784,670	6,784,670	-
Miscellaneous Service Revenues - Account (451)	7,215,245	7,215,245	-
Sales of Water and Water Power - Account (453)	107,480	107,480	-
Rent from Electric Property - Account (454)	18,760,759	18,760,759	-
Interdepartmental Rents - Account (455)	-	-	-
Other Electric Revenues - Account (456)	68,728,424	65,399,708	3,328,716 (c)
Revenues from Transmission of Electricity of Others (456.1)	56,223,453	-	56,223,453 (b)
Total Operating Revenues	\$ 4,243,625,971	\$ 3,327,208,971	\$ 916,417,000

(a) The large industrial line on page 300 includes account 442.2 Industrial Sales of \$826,933,127 and account 442.3 Irrigation Sales of \$87,383,463.

(b) Sales for Resale and Revenues from Transmission of Electricity of Others are not included on page 304 Revenue by Rate Schedule.

(c) Steam sales totaling \$4,322,329 and materials and supplies inventory cost of sales totaling (\$993,613) are not included on page 304 Revenue by Rate Schedule.

Schedule Page: 300 Line No.: 1 Column: \$

The following table is a reconciliation of the unbilled revenue accrual at December 31, 2007 and the reversal of the December 31, 2006 unbilled revenue accrual.

	December 31, 2007
Current year unbilled revenue accrual	\$ 192,299,000
Prior year unbilled revenue accrual reversal	(177,642,000)
Change In Unbilled Revenue Accrual	\$ 14,657,000

FERC FORM NO. 1 (ED. 12-87)

Page 450.1

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 300 Line No.: 1 Column: MWH

The following table is a reconciliation of the unbilled MWH accrual at December 31, 2007 and the reversal of the December 31, 2006 unbilled MWH accrual.

	December 31, 2007
Current year unbilled MWH accrual	3,315,584
Prior year unbilled MWH accrual reversal	(3,217,145)
Change in MWH Accrual	98,439

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential Sales					
2	CALIFORNIA					
3	06CHCK000R- RES CHECK M			1		
4	06LNX00102-LINE EXT 80% G		32			
5	06LNX00109-REF/NREF ADV +		419			
6	06NETMT135 - RES NET METR	87	8,344	8	10,875	0.0959
7	06OALT015R-OUTD AR LGT SR	377	70,541	401	940	0.1871
8	06RESDD00D-RES SRVC	213,729	20,484,868	19,935	10,721	0.0958
9	06RESDDL06-LOW INCOME	86,911	8,044,337	7,623	11,401	0.0926
10	06RESDDM9M-MULTI FAMILY	331	30,155	9	36,778	0.0911
11	06RESDDS8M-MULTI FAM SBMET	1,409	97,535	16	88,063	0.0692
12	ACQUISITION COMMITMENT		24,929			
13	ACQUISITION COMMITMENT		15,564			
14	ALT RATE FOR ENERGY (CARE)		203,000			
15	SMUD REVENUE IMPUTATIONS		56,406			
16	06RESDD00DN - RES SRVC - DEL	104,324	9,900,532	8,011	13,023	0.0949
17	UNBILLED REV - UNCOLLECTIBLE		-2,000			
18	UNBILLED REVENUE	2,190	522,000			0.2384
19	IDAHO					
20	07LNX00010-MNTHLY 80%GUAR		1,020			
21	07LNX00035-ADV 80%MO GUAR		3,556			
22	07NETMT135 -RESIDENTIAL NET	65	3,995	4	16,250	0.0615
23	07NETMT135 -RES NET		-500			
24	07OALCO007-CUST OWN LIGHT	10	2,054	1	10,000	0.2054
25	07OALT07AR-SECURITY AR LG	115	26,664	154	747	0.2319
26	07OALT07AR-SECURITY AR LG		-870			
27	07RESDD001-RES SRVC	390,817	32,802,269	38,599	10,125	0.0839
28	07RESDD001-RES SRVC		-3,469,745			
29	07RESDD0036-RES SRVC-OPTIO	314,163	21,206,989	16,398	19,159	0.0675
30	07RESDD0036-RES SRVC-OPTIO		-3,054,365			
31	BPA BALANCING ACCOUNT		1,826,573			
32	UNBILLED REV - UNCOLLECTIBLE		-3,000			
33	ACQUISITION COMMITMENT		-87,973			
34	ACQUISITION COMMITMENT		-84,069			
35	UNBILLED REVENUE	5,351	355,000			0.0663
36	OREGON					
37	01CHCK000R-RES CHECK MTR			1		
38	01COST0004 - 01RESDD0004	5,408,166	211,066,450			0.0390
39	01FXRENEWFR-Fixed Renewable		-1			
40	01HABIT004 - 01RESDD0004	38,947	1,476,275			0.0379
41	TOTAL Billed	53,292,039	3,312,551,971	1,683,619	31,653	0.0622
42	Total Unbilled Rev.(See Instr. 6)	98,439	14,657,000	0	0	0.1489
43	TOTAL	53,390,478	3,327,208,971	1,683,619	31,712	0.0623

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

- Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
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- The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
- For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
- Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	01LNX00102-LINE EXT 80% G		2,706			
2	01LNX00105-CNTRCT \$ MIN G		21			
3	01LNX00109-REF/NREF ADV +		8,291			
4	01NETMT135-NET METERING		148,150	354		
5	01NETMT135-NET METERING		-15,207			
6	01OALT014R-OUTD AR LGT RE	2,790	394,749	3,084	905	0.1415
7	01OALT014R-OUTD AR LGT RE		-11,943			
8	01PTOU0004 - 01RES00004	18,749	732,264			0.0391
9	01RENEW004 - 01RES00004	155,919	5,820,584			0.0373
10	01RES00004-RES SRVC		244,225,970	466,687		
11	01RES00004-RES SRVC		-25,489,193			
12	01RES0004T - RES Time Option		806,607	1,189		
13	01RES0004T - RES Time Option		-78,229			
14	01UPPL000R-BASE SCH FALL			3		
15	MERGER CREDITS		18			
16	BPA BALANCING ACCOUNT		13,244,429			
17	SB408 RECOVERY		-864,405			
18	SB838 RECOVERY		664,142			
19	SMUD REVENUE IMPUTATIONS		666,989			
20	UNBILLED REV - UNCOLLECTIBLE		-8,000			
21	UNBILLED REVENUE	19,282	3,280,000			0.1701
22	UTAH					
23	08BLSKY01R-BLUESKY ENERGY		-3			
24	08CFR00001-MTH FACILITY S		1,409			
25	08CHCK000R-RES CHECK M			1		
26	08COOLKPRR - Utah Cool Keeper		-20	67,059		
27	08LNX00001-MTHLY 80% GUAR		1,851			
28	08LNX00005-MTHLY MIN GUAR		60			
29	08LNX00013-80% MNTHLY MIN		18,011			
30	08LNX00016 - 80% annual		343			
31	08LNX00108-ANN COST MTHLY		4,861			
32	08MHTP0025-MOBILE HOME	11,754	779,781	11	1,068,545	0.0663
33	08NETMT135 - Net Metering	764	61,932	137	5,577	0.0811
34	08OALT007R-SECURITY AR LG	2,991	781,039	3,331	898	0.2611
35	08PTLD000R-POST TOP LIGHT	224	16,851	66	3,394	0.0752
36	08RES00001-RES SRVC	6,356,136	520,034,533	661,369	9,611	0.0818
37	08RES00002-RES SRVC-OPTIO	2,585	208,616	290	8,914	0.0807
38	08RES00003-LIFELINE PRGRM	183,053	14,676,696	23,490	7,793	0.0802
39	08RES0150-RES ALL E NOT5		24			
40	08RFND1999-RATE RFND		2			
41	TOTAL Billed	53,292,039	3,312,551,971	1,683,619	31,653	0.0622
42	Total Unbilled Rev.(See Instr. 6)	98,439	14,657,000	0	0	0.1489
43	TOTAL	53,390,478	3,327,208,971	1,683,619	31,712	0.0623

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SALES OF ELECTRICITY BY RATE SCHEDULES

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- For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
- Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	08SEAMIN00-SEASNL ANN MIN		46			
2	08UPPL000R-BASE SCH FALL			2		
3	MERGER CREDITS		5			
4	ACQUISITION		301,949			
5	SMUD REVENUE IMPUTATIONS		692,975			
6	UNBILLED REV - UNCOLLECTIBLE		-5,000			
7	UNBILLED REVENUE	3,471	2,628,000			0.7571
8	WASHINGTON					
9	02LNX00109-REF/NREF ADV +		628			
10	BLUESKY ENERGY		-1			
11	02OALTB15R-OUTD AR LGT RES	1,172	151,000	1,264	927	0.1288
12	02OALTB15R-OUTD AR LGT RES		-5,009			
13	02RES0016-RES SRVC	1,579,342	101,030,086	99,275	15,909	0.0640
14	02RES0016-RES SRVC		-7,261,593			
15	02RES0017-BILL ASSISTANC	45,842	2,936,976	2,506	18,293	0.0641
16	02RES0017-BILL ASSISTANCE		-237,546			
17	02RES0018 3 PHASE RES	2,745	193,926	98	28,010	0.0706
18	02RES0018 3 PHASE RES		-11,888			
19	02RES0018X 3 PHASE RES	710	49,346	26	27,308	0.0695
20	02RES0018X 3 PHASE RES		-3,230			
21	CENTRALIA RFND		-7			
22	ACQUISITION COMMITMENT		-97,669			
23	ACQUISITION		129,980			
24	BPA BALANCING ACCOUNT		3,619,335			
25	UNBILLED REV - UNCOLLECTIBLE		3,000			
26	UNBILLED REVENUE	-3,085	305,000			-0.0989
27	WYOMING					
28	05LNX00109-REF/NREF ADV+		153			
29	05NETMT135 - EXPERIMENTAL	113	8,391	10	11,300	0.0743
30	05OALT015R-OUTD AR LGT SR	1,018	154,330	1,175	866	0.1516
31	05RES00002-OPTIONAL	109,378	7,633,136	5,103	21,434	0.0698
32	05RES00002-RES SRVC	787,262	60,512,874	88,222	8,924	0.0769
33	05RES0018-RES 3 PHASE SR	318	25,585	9	35,333	0.0805
34	05RES0018X-RES 3 PHASE SR	455	32,329	4	113,750	0.0711
35	05RFNDCENT-CENTRALIA RFND		-13			
36	09LNX00108-ANN COST MTHLY		196			
37	ACQUISITION COMMITMENT		-94,407			
38	ACQUISITION		-89,734			
39	SMUD REVENUE IMPUTATIONS		87,546			
40	09NETMT135 - RES NET	18	1,494	3	6,000	0.0830
41	TOTAL Billed	53,292,039	3,312,551,971	1,683,619	31,653	0.0622
42	Total Unbilled Rev.(See Instr. 6)	98,439	14,657,000	0	0	0.1489
43	TOTAL	53,390,478	3,327,208,971	1,683,619	31,712	0.0623

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- 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	09RES00002	220	16,650	23	9,565	0.0757
2	UNBILLED REV - UNCOLLECTIBLE		2,000			
3	UNBILLED REVENUE	-2,380	-180,000			0.0756
4	05RES00002-RES SRVC	683	52,848	80	8,538	0.0774
5	05RES00018-RES 3 PHASE SR	4	395	1	4,000	0.0988
6	05UPPL000R-BASE SCH FALL			1		
7	09OALT207R-SECURITY AR LG	89	31,905	103	864	0.3585
8	09NETMT135 - RES NET	71	4,697	1	71,000	0.0662
9	SMUD REVENUE IMPUTATIONS		12,928			
10	05RES00002-OPTIONAL	102	7,050	4	25,500	0.0691
11	09RES00002	40,675	2,875,487	2,222	18,306	0.0707
12	09RES00002	85,727	6,627,874	9,884	8,673	0.0773
13	UNBILLED REVENUE	39	6,000			0.1538
14	Less Multiple Billings			-87,560		
15						
16	Total Residential	15,975,228	1,263,790,936	1,440,688	11,089	0.0791
17						
18	COMMERCIAL SALES					
19	CALIFORNIA					
20	06CHCK000N-NRES CHECK			2		
21	06GNSV0025-GEN SRVC	65,240	7,537,405	6,851	9,523	0.1155
22	06GNSV025F-GEN SRVC-< 20	950	124,951	92	10,326	0.1315
23	06GNSV0A32-GEN SRVC-20KW	81,765	7,707,217	866	94,417	0.0943
24	06LGSV048T-LRG GEN SERV	73,690	4,299,114	9	8,187,778	0.0583
25	06LGSV0A36-LRG GEN SRVC-O	85,850	6,726,982	194	442,526	0.0784
26	06LNX00102-LINE EXT 80% G		8,139			
27	06LNX00105-CNTRCT \$ MIN G		3,606			
28	06LNX00109-REF/NREF ADV +		77,294			
29	06LNX00300 - 80% MONTHLY MIN		2,743			
30	06OALT015N-OUTD AR LGT SR	766	143,835	551	1,390	0.1878
31	06RCFL0042-AIRWAY & ATHLE	184	26,381	38	4,842	0.1434
32	06WHSV0031-COMM WTR	246	23,976	30	8,200	0.0975
33	ACQUISITION COMMITMENT HEAT		18,404			
34	ACQUISITION		11,490			
35	SMUD REVENUE IMPUTATIONS		42,142			
36	06LNX00103-LINE EXT 80% G		30			
37	06LNX00110-REF/NREF ADV +		7,197			
38	UNBILLED REVENUE	1,488	193,000			0.1297
39	IDAHO					
40	07CISH0019-COMM & IND SPA	9,657	691,401	299	32,298	0.0716
41	TOTAL Billed	53,292,039	3,312,551,971	1,683,619	31,653	0.0622
42	Total Unbilled Rev.(See Instr. 6)	98,439	14,657,000	0	0	0.1489
43	TOTAL	53,390,478	3,327,208,971	1,683,619	31,712	0.0623

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

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- 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	07GNSV0006-GEN SRVC-LRG P	195,917	11,744,550	911	215,057	0.0599
2	07GNSV0009-GEN SRVC-HI VO	33,108	1,450,531	1	33,108,000	0.0438
3	07GNSV0023-GEN SRVC-SML P	114,881	9,142,533	5,657	20,308	0.0796
4	07GNSV0035-GEN SRVCOPTION	902	43,775	2	451,000	0.0485
5	07GNSV006A-GEN SRVC-LRG P	30,272	1,987,196	214	141,458	0.0656
6	07GNSV006A-GEN SRVC-LRG P		-487,833			
7	07GNSV023A-GEN SRVC-SML P	15,697	1,332,258	1,135	13,830	0.0849
8	07GNSV023A-GEN SRVC-SML P		-145,390			
9	07GNSV023F-GEN SRVC SML P	16	2,390	7	2,286	0.1494
10	07LNX00010-MNTHLY 80%GUAR		15,196			
11	07LNX00035-ADV 80%MO GUAR		250,886			
12	07LNX00040-ADV+REFCHG+80%		30,466			
13	07OALT007N-SECURITY AR LG	262	52,110	198	1,323	0.1989
14	07OALT07AN-SECURITY AR LG	13	3,034	16	813	0.2334
15	07OALT07AN-SECURITY AR LG		-98			
16	07LNX00312 -LINE EXT		5,573			
17	07LNX00015-ANNUAL 80%GUAR		2,412			
18	07LNX00311 - LINE EXT 80%		9,806			
19	07LNX00020 -MONTHLY		667			
20	07LNX00300 - 80% MONTHLY MIN		2,243			
21	ACQUISITION COMMITMENT		-51,146			
22	ACQUISITION		-48,876			
23	BPA BALANCING ACCOUNT		105,158			
24	UNBILLED REVENUE	-2,613	-127,000			0.0486
25	OREGON					
26	01COST0023,GEN SRV,CST BASE	993,763	39,290,675			0.0395
27	01COST0048-01LGSV0048	727,288	26,320,594			0.0362
28	01COST023F -GEN SRV -	3,271	138,536			0.0424
29	01COSTB023-GEN SRV, CST-BSD	90,915	3,738,989			0.0411
30	01COSTL030-LRG GEN SRV, CST	1,050,776	39,747,004			0.0378
31	01COSTS028, GEN SERV, COST >	1,956,597	76,061,308			0.0389
32	01COSTS030-GEN SRV CBS >200	1,149	40,550			0.0353
33	01GNSB0023 -BPA DISC,<30kW		-420,423			
34	01GNSB0023,GEN SRV,BPA,<30		5,116,666	14,468		
35	01GNSB0028-GEN SRVC,BPA,>		-638,210			
36	01GNSB0028,GEN SRV,BPA,>30		3,015,048	569		
37	01GNSB023T-GEN SRV-TOU-B		35,453	62		
38	01GNSB023T-GEN SRVC,TOU,BP		-4,133			
39	01GNSV0023,GEN SRV,< 30KW		36,608,361	54,053		
40	01GNSV0028,GEN SRV >30kW		42,207,448	8,814		
41	TOTAL Billed	53,292,039	3,312,551,971	1,683,619	31,653	0.0622
42	Total Unbilled Rev.(See Instr. 6)	98,439	14,657,000	0	0	0.1489
43	TOTAL	53,390,478	3,327,208,971	1,683,619	31,712	0.0623

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SALES OF ELECTRICITY BY RATE SCHEDULES

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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	01GNSV023F-GEN SRV-FLAT RA	10,203	1,235,130	873	11,687	0.1211
2	01GNSV023M-GEN SRV,MANUAL B	78	4,953	1	78,000	0.0635
3	01GNSV023T,GEN SRV,TOU Optio		166,773	250		
4	01HABT0023,HABITAT BLENDED	1,780	71,831			0.0404
5	01HABTB023-HABITAT BLENDED	150	6,365			0.0424
6	01LGSB0030,GEN DEL SRV,>200		-231,119			
7	01LGSB0030,GEN DEL SRV,>200		864,953	31		
8	01LGSV0028,LRG GEN SRV<1000		-42,414			
9	01LGSV0030-LRG GEN SRV,>10		17,421,842	635		
10	01LGSV0048-1000KW AND OVR		8,163,733	90		
11	01LGSV048M-LRG GEN SRVC 1	51,625	2,167,840	1	51,625,000	0.0420
12	01LNX00100-LINE EXT 60% G		8,269			
13	01LNX00102-LINE EXT 80% G		383,546			
14	01LNX00103-LINE EXT 80% G		12,703			
15	01LNX00105-CNTRCT \$ MIN G		15,098			
16	01LNX00109-REF/NREF ADV +		1,249,175			
17	01LNX00110-REF/NREF ADV +		10,912			
18	01LNX00120-Line Extension 60% G		5,964			
19	01LNX00300-LINE EXT 80%		13,038			
20	01LNX00311-LINE EXT 80% G		27,214			
21	01LNX00312-IRG LINE EXT		175			
22	01LPRS047M-PART REQ SRVC	5,118	442,033	3	1,706,000	0.0864
23	01NMT2313-NET MTR, GEN, < 3		13,174	28		
24	01OALT014N-OUTD AR LGT NR	1,701	248,565	1,210	1,406	0.1461
25	01OALT014N-OUTD AR LGT NR		-7,295			
26	01OALT015N-OUTD AR LGT NR	6,371	804,101	3,195	1,994	0.1262
27	01PTOU0023,GEN SRV, TOU ENG	4,119	160,856			0.0391
28	01PTOUB023,GEN SRV, TOU SPLY	775	29,422			0.0380
29	01RCFL0054-REC FIELD LGT	925	82,107	102	9,069	0.0888
30	01RENW0023,RENW USAGE SPLY	6,648	269,610			0.0406
31	01RENWB023 -RENEWABLE	628	26,128			0.0416
32	01STDAY02 -DAY STD OFR, SCH	1,772	94,215			0.0532
33	01STDAY028-DAY STD OFF, SCH	3,305	174,302			0.0527
34	01STDAY030-STD DAY OFF, SCH	4,480	235,582			0.0526
35	MERGER CREDITS		22			
36	BPA BALANCING ACCOUNT		688,651			
37	01LGSB0048-LG GEN		-16,097			
38	01LGSB0048-LG GEN		41,828	1		
39	01NMT28135-NET MTR, GEN,>3		36,499	9		
40	01LGSV028M-LGSV,<1000 kW, M	471	30,499	1	471,000	0.0648
41	TOTAL Billed	53,292,039	3,312,551,971	1,683,619	31,653	0.0622
42	Total Unbilled Rev.(See Instr. 6)	98,439	14,657,000	0	0	0.1489
43	TOTAL	53,390,478	3,327,208,971	1,683,619	31,712	0.0623

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1	01GNSV030M-GEN SRV,200kW,	5,449	290,002	1	5,449,000	0.0532
2	01GNSV0728-GEN SVC DIR		32,400	2		
3	01GNSV0730-GEN SVC DIR		955,676	38		
4	01GNSV0748 LG GEN SVC DIR		41,169	1		
5	SB408 RECOVERY		-800,440			
6	SB838 RECOVERY		559,549			
7	SMUD REVENUE IMPUTATIONS		577,369			
8	UNBILLED REVENUE	13,437	1,758,000			0.1308
9	UTAH					
10	08CFR00051-MTH FAC SRVCHG		66,690			
11	08CFR00052-ANN FAC SVCCHG		2			
12	08CHCK000N-NRES CHECK			3		
13	08COOLKPRN - A/C DIRECT LOAD			2,942		
14	08GNSV0006-GEN SRVC-DISTR	4,719,377	295,992,725	10,982	429,737	0.0627
15	08GNSV0009-GEN SRVC-HI VO	241,802	10,126,176	19	12,726,421	0.0419
16	08GNSV0023-GEN SRVC-DISTR	1,190,085	89,235,279	62,766	18,961	0.0750
17	08GNSV006A-GEN SRVC-ENERG	191,892	15,916,282	1,623	118,233	0.0829
18	08GNSV006B-GEN SRVC-DEM&	2,699	170,446	10	269,900	0.0632
19	08GNSV006M-MNL DIST VOLTG	8,390	415,374	7	1,198,571	0.0495
20	08GNSV009A-GEN SRVC HI VO	27,272	1,250,918	2	13,636,000	0.0459
21	08GNSV009M-MANL HIGH VOLT	20,550	841,166	1	20,550,000	0.0409
22	08GNSV023F-GEN SRVC FIXED	1,434	148,595	116	12,362	0.1036
23	08GNSV023M-GNSV DIST VOLT	109	8,411	6	18,167	0.0772
24	08GNSV06AM-MNL ENERGY TOD	769	69,649	2	384,500	0.0906
25	08GNSV06MN-GNSV DIST VOLT	28,185	1,588,432	405	69,593	0.0564
26	08GNSV09AM-MAN TOD HIVOLT	168	9,601	1	168,000	0.0571
27	08LNX00002-MTHLY 80% GUAR		443,142			
28	08LNX00004-ANNUAL 80%GUAR		90,384			
29	08LNX00006-FIXD MTHLY MIN		13,926			
30	08LNX00014-80% MIN MNTHLY		1,619,165			
31	08LNX00017-ADV/REF&80%ANN		137,752			
32	08LNX00150-AGR MTH GUAR M		852			
33	08LNX00158-ANNUALCOST MTH		34,608			
34	08LNX00300-LINE EXT 80% PLUS		199,988			
35	08LNX00310-IRR 80% ANNUAL MIN		512			
36	08LNX00312 IRG LINE EXT		1,066			
37	08NMT23135-NET MTR,GEN,< 2	76	6,410	7	10,857	0.0843
38	08OALT007N-SECURITY AR LG	9,263	1,960,186	4,809	1,926	0.2116
39	08POLE0075-POLES W/LIGHT		1,221	7		
40	08PRSV031M-BKUP MNT&SUPPL	14,447	849,317	3	4,815,667	0.0588
41	TOTAL Billed	53,292,039	3,312,551,971	1,683,619	31,653	0.0622
42	Total Unbilled Rev.(See Instr. 6)	98,439	14,657,000	0	0	0.1489
43	TOTAL	53,390,478	3,327,208,971	1,683,619	31,712	0.0623

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1	08PTLD000N-POST TOP LIGHT	65	4,872	8	8,125	0.0750
2	08SLC1202F-TRAFFIC SIG NM	206	15,841	32	6,438	0.0769
3	08SLCU1202-TRAF & OTHER S	1,098	88,695	416	2,639	0.0808
4	08SLCU1203-MTR OUTDONIGHT	9,774	689,942	265	36,883	0.0706
5	MERGER CREDITS		-7			
6	ACQUISITION		355,253			
7	SMUD REVENUE IMPUTATIONS		797,863			
8	08LNX00311-LINE EXT 80%		60,765			
9	08GNSV0008-GEN SVC TOU>100	925,190	50,078,176	132	7,009,015	0.0541
10	08GNSV0008M-GEN SVC TOU>100	46,855	2,704,857	6	7,809,167	0.0577
11	UNBILLED REVENUE	24,901	3,216,000			0.1292
12	WASHINGTON					
13	02GNSB0024-GEN SRVC DO	41,717	2,929,486	3,180	13,119	0.0702
14	02GNSB0024-GEN SRVC DO		-172,018			
15	02GNSB024F-GEN SRVC DOM/F	228	20,255	9	25,333	0.0888
16	02GNSB024F-GEN SRVC DOM/F		-156			
17	02GNSB24FP-GEN SVC	405	99,744	107	3,785	0.2463
18	02GNSB24FP-GEN SVC		-3,017			
19	02GNSV0024-GEN SRVC	464,956	29,838,106	13,523	34,383	0.0642
20	02GNSV024F-GEN SRVC-FL	1,211	115,540	122	9,926	0.0954
21	02LGSB0036-LRG GEN SVC IRG	86,232	4,506,151	95	907,705	0.0523
22	02LGSB0036-LRG GEN SVC IRG		-363,637			
23	02LGSV0036-LRG GEN SRV	674,915	36,048,841	811	832,201	0.0534
24	02LGSV048T-LRG GEN SRVC 1	153,043	7,333,945	27	5,668,259	0.0479
25	02LNX00102-LINE EXT 80% G		55,619			
26	02LNX00103-LINE EXT 80% G		4,132			
27	02LNX00105-CNTRCT \$ MIN G		692			
28	02LNX00109-REF/NREF ADV +		162,752			
29	02LNX00110-REF/NREF ADV +		12,557			
30	02LNX00112-YR INCURRED CH		669			
31	02LNX00300-LINE EXT 80% G		4,665			
32	02LNX00311- LINE EXT 80%		1,647			
33	02OALT015N-OUTD AR LGT	1,700	201,867	891	1,908	0.1187
34	02OALT015N-OUTD AR LGT NR	650	82,850	563	1,155	0.1275
35	02OALT015N-OUTD AR LGT NR		-2,782			
36	02RCFL0054-REC FIELD L	227	18,033	28	8,107	0.0794
37	CENTRALIA RFND		-141			
38	MERGER CREDITS		16			
39	02NMT24135, Net metering	5	454	1	5,000	0.0908
40	ACQUISITION COMMITMENT		-86,849			
41	TOTAL Billed	53,292,039	3,312,551,971	1,683,619	31,653	0.0622
42	Total Unbilled Rev.(See Instr. 6)	98,439	14,657,000	0	0	0.1489
43	TOTAL	53,390,478	3,327,208,971	1,683,619	31,712	0.0623

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1	ACQUISITION COMMITMENT		115,580			
2	BPA BALANCING ACCOUNT		322,616			
3	UNBILLED REVENUE	-6,503	-99,000			0.0152
4	WYOMING					
5	05CHCK000N-NRES CHECK			1		
6	05GNSV0025-GEN SRVC	1,070,439	70,447,298	20,440	52,370	0.0658
7	05GNSV025F-GEN SRVC-FL RA	1,031	122,571	194	5,314	0.1189
8	05LGSV046M-LRG GEN SRV	976	46,061	1	976,000	0.0472
9	05LGSV046T-LRG GEN SERV	213,878	10,330,523	19	11,256,737	0.0483
10	05LNX00100-LINE EXT 60% G		170			
11	05LNX00102-LINE EXT 80% G		550,268			
12	05LNX00105-CNTRCT \$ MIN G		5,373			
13	05LNX00109-REF/NREF ADV +		433,575			
14	05LNX00114-TEMP SVC 12MO>		3,622			
15	05NMT25135-NET MTR,GEN,< 2	458	37,806	3	152,667	0.0825
16	05OALT015N-OUTD AR LGT SR	3,081	468,095	1,822	1,691	0.1519
17	05RCFL0054-REC FIELD L	652	51,422	52	12,538	0.0789
18	CENTRALIA RFND		18			
19	09GNSV0025-GEN SVC-SINGLE	1	261	1	1,000	0.2610
20	05LNX00300-LINE EXT 80%		688,646			
21	05LNX00310-LINE EXT 80%		20,921			
22	ACQUISITION COMMITMENT		-129,151			
23	ACQUISITION COMMITMENT		-122,757			
24	SMUD REVENUE IMPUTATIONS		125,619			
25	UNBILLED REVENUE	-8,520	-630,000			0.0739
26	05GNSV0025-GEN SRVC	1,359	120,231	48	28,313	0.0885
27	05GNSV025F-GEN SRVC-FL RA	211	20,542	32	6,594	0.0974
28	05LNX00102-LINE EXT 80% G		5,749			
29	05LNX00109-REF/NREF ADV +		67,450			
30	05LNX00110-REF/NREF ADV +		2,213			
31	05LNX00114-TEMP SVC 12MO>		55			
32	09GNSV0025-GEN SVC-SINGLE	129,484	8,507,479	2,383	54,337	0.0657
33	09GNSV025F-GEN SVC-FIXED	44	4,270	7	6,286	0.0970
34	09GNSV025M-GEN SVC-MANUAL	2,362	149,232	2	1,181,000	0.0632
35	09OALT207N-SECURITY AR LG	279	93,553	145	1,924	0.3353
36	09SLCU2123-MTR OUTDONIGHT	52	3,570	2	26,000	0.0687
37	05LNX00300-LINE EXT 80%		2,821			
38	05LNX00311-LINE EXT 80%		1,337			
39	SMUD REVENUE IMPUTATIONS		13,920			
40	UNBILLED REVENUE	1,057	72,000			0.0681
41	TOTAL Billed	53,292,039	3,312,551,971	1,683,619	31,653	0.0622
42	Total Unbilled Rev.(See Instr. 6)	98,439	14,657,000	0	0	0.1489
43	TOTAL	53,390,478	3,327,208,971	1,683,619	31,712	0.0623

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

- Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
- Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
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- 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	Less Multiple Billings			-26,021		
2						
3	COMMERCIAL SALES TOTAL	15,951,322	1,014,421,434	204,569	77,975	0.0636
4						
5	INDUSTRIAL SALES					
6	CALIFORNIA					
7	06GNSV0025-GEN SRVC	1,020	118,162	101	10,099	0.1158
8	06GNSV0A32-GEN SRVC-20 KW	1,948	213,743	23	84,696	0.1097
9	06LGSV048T-LRG GEN SERV	50,284	2,895,055	5	10,056,800	0.0576
10	06LGSV0A36-LRG GEN SRVC-O	7,069	601,035	15	471,267	0.0850
11	06LNX00109-REF/NREF ADV +		1,516			
12	ACQUISITION COMMITMENT		3,935			
13	ACQUISITION		2,457			
14	SMUD REVENUE IMPUTATIONS		8,841			
15	UNBILLED REVENUE	867	82,000			0.0946
16	IDAHO					
17	07CFR00001-MTH FACILITY S		2,217			
18	07CISH0019-COMM & IND SPA	175	13,192	7	25,000	0.0754
19	07GNSV0006-GEN SRVC-LRG P	107,449	5,605,085	117	918,368	0.0522
20	07GNSV0008-GEN SRVC-MEDIU	2,473	136,299	2	1,236,500	0.0551
21	07GNSV0009-GEN SRVC-HI VO	84,460	3,761,075	11	7,678,182	0.0445
22	07GNSV0023-GEN SRVC-SML P	10,562	816,703	356	29,669	0.0773
23	07GNSV0035-GEN SRVCOPTION	1,427	69,365	1	1,427,000	0.0486
24	07GNSV006A-GEN SRVC-LRG P	5,146	324,561	34	151,353	0.0631
25	07GNSV006A-GEN SRVC-LRG P		-39,107			
26	07GNSV023A-GEN SRVC-SML P	2,308	213,702	260	8,877	0.0926
27	07GNSV023A-GEN SRVC-SML P		-19,153			
28	07GNSV023S-TRAFFIC SIGNALS	3	505	3	1,000	0.1683
29	07LNX00035-ADV 80%MO GUAR		1,501			
30	07LNX00108-ANN COST MTHLY		1,996			
31	07LNX00300-80% MONTHLY MIN		295			
32	07OALT007N-SECURITY AR LG	12	2,592	16	750	0.2160
33	07OALT07AN-SECURITY AR LG	2	437	3	667	0.2185
34	07OALT07AN-SECURITY AR LG		-12			
35	07SLCU1201-TRAF SIGNAL SY	2	319	3	667	0.1595
36	07SPCL0001	1,320,600	48,229,649	1	1,320,600,000	0.0365
37	07SPCL0002	98,958	3,657,795	1	98,958,000	0.0370
38	ACQUISITION COMMITMENT		-218,727			
39	ACQUISITION		-209,019			
40	BPA BALANCING ACCOUNT		20,646			
41	TOTAL Billed	53,292,039	3,312,551,971	1,683,619	31,653	0.0622
42	Total Unbilled Rev.(See Instr. 6)	98,439	14,657,000	0	0	0.1489
43	TOTAL	53,390,478	3,327,208,971	1,683,619	31,712	0.0623

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SALES OF ELECTRICITY BY RATE SCHEDULES

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- 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	UNBILLED REVENUE	33,573	1,286,000			0.0383
2	OREGON					
3	01COST0023,GEN SRV,COSTBASE	22,670	896,334			0.0395
4	01COST0048 -01LGSV0048	1,690,183	60,260,602			0.0357
5	01COST023F-GEN SRV COST BA	3	148			0.0493
6	01COSTB023-GEN SRV,CST-BSD	325	13,615			0.0419
7	01COSTL030-LRG GEN SRV, CST	258,663	9,834,304			0.0380
8	01COSTS028,GEN SERV, COST >	115,440	4,485,583			0.0389
9	01GNSB0023-BPA DISC, < 30 KW		-1,460			
10	01GNSB0023,GEN SRV, BPA,<30		22,535	65		
11	01GNSB0028-GEN SRVC, BPA, >		-2,831			
12	01GNSB0028,GEN SRV,BPA,>30		23,466	7		
13	01GNSV0023,GEN SRV,<30KW		894,142	1,165		
14	01GNSV0028,GEN SRV>30kW		3,142,290	545		
15	01GNSV023F-GEN SRV-FLATRT		659	3		
16	01GNSV023M -GEN SRV, MANUAL	2	652	1	2,000	0.3260
17	01GNSV023T GEN SRV, TOU Optio		3,483	4		
18	01HABT0023,HABITAT BLEND	76	2,780			0.0366
19	01LGSB0030,GEN DELSRV>200		-9,316			
20	01LGSB0030,GEN DELSRV>200		36,959	1		
21	01LGSB0048-LG GEN SVC>1000		-830			
22	01LGSB0048-LG GEN		5,193	1		
23	01LGSV0030-LRG GEN SRV>10		5,823,183	189		
24	01LGSV0048-1000KW AND OVR		16,274,808	116		
25	01LGSV048M-LRG GEN SRVC 1	562,157	20,051,484	5	100,431,400	0.0399
26	01LNX00102-LINE EXT 80% G		2,243			
27	01LNX00105-CNTRCT \$ MIN G		3,177			
28	01LNX00109-REF/NREF ADV +		1,532			
29	01LNX00300-LINE EXT 80%		705			
30	01LPRS047M-PART REQ SRVC	593,056	23,652,895	4	148,264,000	0.0399
31	01NMT28135-NET MTR, GEN, > 3		4,517	1		
32	01OALT014N-OUTD AR LGT NR	5	742	6	833	0.1484
33	01OALT014N-OUTD AR LGT NR		-27			
34	01OALT015N-OUTD AR LGT NR	383	46,151	159	2,409	0.1205
35	001PTOU0023,GEN SRV, TOU ENG	76	3,056			0.0402
36	01RENW0023,RENW USAGE SPLY	224	9,184			0.0410
37	01RENWB023 -RENEWABLE	1	40			0.0400
38	BPA BALANCING ACCOUNT		7,885			
39	01STDAY023-DAY STD OFR,SCH	43	2,220			0.0516
40	01LGSV028M -LGSV,<1000KW	55	4,482	1	55,000	0.0815
41	TOTAL Billed	53,292,039	3,312,551,971	1,683,619	31,653	0.0622
42	Total Unbilled Rev.(See Instr. 6)	98,439	14,657,000	0	0	0.1489
43	TOTAL	53,390,478	3,327,208,971	1,683,619	31,712	0.0623

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SALES OF ELECTRICITY BY RATE SCHEDULES

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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	SB408 RECOVERY		-506,730			
2	SB838 RECOVERY		371,475			
3	SMUD REVENUE IMPUTATIONS		388,213			
4	UNBILLED REVENUE	8,602	782,000			0.0909
5	UTAH					
6	08CFR00051-MTH FAC SRVCHG		16,329			
7	08EFOP0021-ELEC FURNACE O	1,815	130,330	2	907,500	0.0718
8	08EFOP021M-ELEC FURNACE O	1,612	153,229	3	537,333	0.0951
9	08GNSV0006-GEN SRVC-DISTR	800,317	52,623,648	1,337	598,592	0.0658
10	08GNSV0009-GEN SRVC-HI VO	2,491,833	98,373,226	110	22,653,027	0.0395
11	08GNSV0023-GEN SRVC-DISTR	62,439	4,752,017	3,799	16,436	0.0761
12	08GNSV006A-GEN SRVC-ENERG	49,613	4,668,949	241	205,863	0.0941
13	08GNSV006B-GEN SRVC-DEM&	3,045	222,021	6	507,500	0.0729
14	08GNSV006M-MNL DIST VOLTG	3,068	164,520	1	3,068,000	0.0536
15	08GNSV009A-GEN SRVC HI VO	18,466	1,049,447	6	3,077,667	0.0568
16	08GNSV009M-MANL HIGH VOLT	791,582	29,908,098	11	71,962,000	0.0378
17	08GNSV023F-GEN SRVC FIXED	4	1,830	2	2,000	0.4575
18	08GNSV06MN-GNSV DIST VOLT	1,117	73,490	27	41,370	0.0658
19	08GNSV09AM-MAN TOD HIVOLT	1,578	121,856	1	1,578,000	0.0772
20	08LNX00002-MTHLY 80% GUAR		28,676			
21	08LNX00004-ANNUAL 80%GUAR		362			
22	08LNX00014-80% MIN MNTHLY		56,846			
23	08LNX00017-ADV/REF&80%ANN		3,056			
24	08LNX00150-AGR MTH GUAR M		864			
25	08LNX00300 - LINE EXT 80% PLUS		5,015			
26	08LNX00958-LINE EXT CNTRC		-4,663			
27	08OALT007N-SECURITY AR LG	1,468	289,686	545	2,694	0.1973
28	08PRSV031M-BKUP MNT&SUPPL	975	309,054	1	975,000	0.3170
29	08SLCU1202-TRAF & OTHER S	43	3,129	9	4,778	0.0728
30	08SLCU1203-MTR OUTDONIGHT	12	2,937	6	2,000	0.2448
31	08SPCL0001	591,691	21,985,733	1	591,691,000	0.0372
32	08SPCL0002	859,186	24,291,917	1	859,186,000	0.0283
33	08SPCL0003	628,031	20,791,684	1	628,031,000	0.0331
34	08SPCL0005	257,898	8,595,539	1	257,898,000	0.0333
35	08SPCL0011	6,330	445,704			0.0704
36	MERGER CREDITS		4			
37	ACQUISITION		363,932			
38	SMUD REVENUE IMPUTATIONS		823,543			
39	08GNSV06AM-MNL ENERGY TOD	96	10,009	1	96,000	0.1043
40	08GNSV0008-GEN SVC TOU>100	974,230	54,868,938	112	8,698,482	0.0563
41	TOTAL Billed	53,292,039	3,312,551,971	1,683,619	31,653	0.0622
42	Total Unbilled Rev.(See Instr. 6)	98,439	14,657,000	0	0	0.1489
43	TOTAL	53,390,478	3,327,208,971	1,683,619	31,712	0.0623

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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	08GNSV008M-GEN SVC TOU > 100	66,399	3,634,222	8	8,299,875	0.0547
2	UNBILLED REVENUE	-8,856	175,000			-0.0198
3	WASHINGTON					
4	02GNSB0024-GEN SRVC DO	3,254	215,281	105	30,990	0.0662
5	02GNSB0024-GEN SRVC DO		-10,526			
6	02GNSB24FP-GEN SVC	7	1,973	1	7,000	0.2819
7	02GNSB24FP-GEN SVC		-20			
8	02GNSV0024-GEN SRVC	18,006	1,159,532	376	47,888	0.0644
9	02GNSV024F- GEN SRVC-FL	33	5,796	4	8,250	0.1756
10	02LGSV0036-LRG GEN SRV	136,630	7,424,663	128	1,067,422	0.0543
11	02LGSV048M-LRG GEN SRV	25,831	1,639,796	1	25,831,000	0.0635
12	02LGSV048T-LRG GEN SRVC 1	674,725	29,173,220	34	19,844,853	0.0432
13	02OALT015N-OUTD AR LGT	127	14,250	43	2,953	0.1122
14	02OALTB15N-OUTD AR LGT NR	32	4,114	19	1,684	0.1286
15	02OALTB15N-OUTD AR LGT NR		-142			
16	02PRSV47TM-LRG PART REQMT	1,540	148,326	1	1,540,000	0.0963
17	CENTRALIA RFND		45			
18	MERGER CREDITS		-6			
19	02LGSB0036-LRG GEN SVC IRG	3,876	347,660	27	143,556	0.0897
20	02LGSB0036-LRG GENSVC IRG		-4,950			
21	02LGSB048T - GEN SRVC, NO BPA			1		
22	ACQUISITION COMMITMENT		-64,803			
23	ACQUISITION		86,241			
24	BPA BALANCING ACCOUNT		8,941			
25	UNBILLED REVENUE	-5,046	-132,000			0.0262
26	WYOMING					
27	05GNSV0025-GEN SRVC	296,668	17,237,724	1,659	178,823	0.0581
28	05GNSV025F-GEN SRVC-FL RA	83	8,420	16	5,188	0.1014
29	05GNSV025M-GEN SRVC Manu	1,632	82,206	1	1,632,000	0.0504
30	05LGSV046M-LRG GEN SRV	486,966	20,541,214	4	121,741,500	0.0422
31	05LGSV046T-LRG GEN SERV	1,256,496	57,547,143	57	22,043,789	0.0458
32	05LGSV048M-TOU>1000KW MAN	1,199,937	40,829,348	3	399,979,000	0.0340
33	05LGSV048T-LRG GENSERV TIM	878,776	30,762,317	9	97,641,778	0.0350
34	05LNX00100-LINE EXT 60% G		17,388			
35	05LNX00102-LINE EXT 80% G		162,892			
36	05LNX00105-CNTRCT \$ MIN G		46,748			
37	05LNX00109-REF/NREF ADV +		187,544			
38	05OALT015N-OUTD AR LGT SR	89	12,452	47	1,894	0.1399
39	05PRSV033M-PART SERV REQ	1,082,268	44,181,740	5	216,453,600	0.0408
40	ACQUISITION COMMITMENT		-577,286			
41	TOTAL Billed	53,292,039	3,312,551,971	1,683,619	31,653	0.0622
42	Total Unbilled Rev.(See Instr. 6)	98,439	14,657,000	0	0	0.1489
43	TOTAL	53,390,478	3,327,208,971	1,683,619	31,712	0.0623

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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	ACQUISITION		-548,707			
2	SMUD REVENUE IMPUTATIONS		518,781			
3	05LNX00300-LINE EXT 80%		-8,662			
4	UNBILLED REVENUE	27,937	1,321,000			0.0473
5	05GNSV0025-GEN SRVC	798	41,279	7	114,000	0.0517
6	05LGSV046T-LRG GEN SERV	25,006	1,217,909	4	6,251,500	0.0487
7	05LGSV048M-TOU>1000KW MAN	393,521	13,765,368	6	65,586,833	0.0350
8	05LGSV048T-LRG GENSRV TIM	351,721	12,616,189	7	50,245,857	0.0359
9	05LNX00102-LINE EXT 80% G		534,272			
10	05LNX00109-REF/NREF ADV +		1,701			
11	05PRSV033M-PART SERV REQ		106,236	1		
12	09GNSV0025-GEN SVC-SINGLE	41,545	2,544,122	380	109,329	0.0612
13	09GNSV025M-GEN SVC-MANUAL	4,849	244,206	3	1,616,333	0.0504
14	09OALT207N-SECURITY AR LG	6	1,766	3	2,000	0.2943
15	09PRSV033M	1,308	187,140	1	1,308,000	0.1431
16	SMUD REVENUE IMPUTATIONS		84,906			
17	UNBILLED REVENUE	906	192,000			0.2119
18	Less Multiple Billings			-1,088		
19						
20	INDUSTRIALSALES TOTAL	19,433,821	826,933,127	11,329	1,715,405	0.0426
21						
22	IRRIGATION SALES					
23	CALIFORNIA					
24	06APSV0020-AG PMP SRVC	68,604	6,013,645	1,331	51,543	0.0877
25	06LNX00102-LINE EXT 80% G		916			
26	06LNX00103-LINE EXT 80% G		1,476			
27	06LNX00110-REF/NREF ADV +		9,489			
28	06LNX00312-IRG LINE EXT		719			
29	06SLX00001-KLAM FALLS MIN		27			
30	06USBR0040-KLAM IRG ONPRJ	33,153	1,246,121	673	49,262	0.0376
31	06LNX00109-REF/NREF ADV +		180			
32	IRRIGATION UNBILLED	-17	-3,000			0.1765
33	IDAHO					
34	07APSA010L IRG & Pump BPA		-8,929,856			
35	07APSA010L IRG & Pump Large	558,368	36,026,822	3,386	164,905	0.0645
36	07APSA010S IRG & Pump BPA		-83,650			
37	07APSA010S IRG & Pump Small	5,280	421,842	393	13,435	0.0799
38	07APSAL10X IRG & PUMP - Large I	86,732	5,883,079	629	137,889	0.0678
39	07APSAS10X IRG & PUMP - Small I	1,413	127,393	195	7,246	0.0902
40	07APSC010L IRG PUMP Srv BPA		-1,615			
41	TOTAL Billed	53,292,039	3,312,551,971	1,683,619	31,653	0.0622
42	Total Unbilled Rev.(See Instr. 6)	98,439	14,657,000	0	0	0.1489
43	TOTAL	53,390,478	3,327,208,971	1,683,619	31,712	0.0623

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

- Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
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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	07APSC010L IRG PUMP Srv Large	41	-313			-0.0076
2	07APSVCNLL-LRG LOAD	41,580	2,425,104	74	561,892	0.0583
3	07APSVCNLL-LRG LOAD CANAL		-608,261			
4	07APSVCNLS-SML LOAD CANAL	234	18,060	14	16,714	0.0772
5	07APSVCNLS-SML LOAD CANAL		-3,800			
6	07BPADEBIT-BPA ADJUST FEE		2,115,080			
7	07LNX00015-ANNUAL 80%GUAR		10,690			
8	07LNX00040-ADV+REFCHG+80%		128,757			
9	07LNX00107-SUBD ADV & AIC		1,097			
10	07LNX00310 80% ANNUAL		4,138			
11	07LNX00312-LINE EXT		8,891			
12	07APSN010L-LG IRR & PUMP	3,376	237,075	31	108,903	0.0702
13	07APSN010L-LG, IRR, 3 PH, BP		-50,067			
14	07APSN010S-IRR, SMALL, 3 PH,		-3,345			
15	07APSN010S-IRRIGATION, SMALL,	203	15,811	11	18,455	0.0779
16	07APSNS10X-IRRIGATION, SMALL,	49	4,270	3	16,333	0.0871
17	IRRIGATION BPA BAL ACCT		7,462,188			
18	IRRIGATION LOAD CNTRL CR		-450,000			
19	UNBILLED REV - IRRIGATION	-3				
20	OREGON					
21	01APSV0041-AG PMP SRVC BP		1,967,934	4,759		
22	01APSV0041-AG PMP SRVC BP		-96,737			
23	01APSV041L-Pumping Serv >30KW		2,846,204	1,057		
24	01APSV041L-Pumping Serv BPA >3		-167,551			
25	01APSV041T-AGR PUMP SRV TOU		-1,025			
26	01APSV041T-AGR PUMP SRV-TOU		26,978	59		
27	01APSV041X-AG PMP SRVC		77,230	223		
28	01APSV41XL-Pumping Serv no BPA		114,455	42		
29	01BPADEBIT-BPA ADJUST FEE		28,202			
30	01COST0041-01APSV0041-01APSV	136,279	5,299,604			0.0389
31	01COST0048-01LGSV0048	9,355	332,310			0.0355
32	01COSTS028,GEN SERV COST > 3	286	11,190			0.0391
33	01GNSV0028,GEN SRV>30 kW		8,190	2		
34	01HABIT041-01APSV0041AG PMP	1	28			0.0280
35	01LGSB0048-LG GEN		-23,823			
36	01LGSB0048-LG GEN SVC>1000		97,600	2		
37	01LNX00102-LINE EXT 80% G		184			
38	01LNX00103-LINE EXT 80% G		15,310			
39	01LNX00109-REF/NREF ADV +		806			
40	01LNX00110-REF/NREF ADV +		79,224			
41	TOTAL Billed	53,292,039	3,312,551,971	1,683,619	31,653	0.0622
42	Total Unbilled Rev.(See Instr. 6)	98,439	14,657,000	0	0	0.1489
43	TOTAL	53,390,478	3,327,208,971	1,683,619	31,712	0.0623

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SALES OF ELECTRICITY BY RATE SCHEDULES

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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	01PTOU0041-01APSV0041 AG PMP	643	21,201			0.0330
2	01RENEW041-01APSV0041 AG	100	3,911			0.0391
3	01SLX00005-KLAMATH FALLS		116,280			
4	01SLX00013-K FALLS IRG MI		4,366			
5	01SLX00014-K FALLS IRG MI		-26			
6	01STDAY041-Daily Standard Offer	8	300			0.0375
7	01USBGV033-KLAMATH IRG TOU		-63			
8	01USBOF033-KLAMATH BASIN	51,901	691,180	662	78,400	0.0133
9	01USBOF033-KLAMATH BASIN		-63,968			
10	01USBON033-KLAMATH BASIN	59,778	673,178	1,410	42,396	0.0113
11	01USBON033- KLAMATH BASIN		-72,635			
12	01USBGV033-IRG TOU W/O BPA	2,812	19,109	10	281,200	0.0068
13	MERGER CREDITS		-4			
14	BPA BALANCING ACCOUNT		384,565			
15	IRRIGATION UNBILLED	-41	-9,000			0.2195
16	Irrigation - BPA adjustment		5,923			
17	01LNX00312 - IRG LINE EXT		2,521			
18	SB408 RECOVERY		-23,366			
19	SB838 RECOVERY		13,215			
20	UTAH					
21	08APSV0010-IRR & SOIL DRA	200,303	10,702,821	2,493	80,346	0.0534
22	08APSV10NS-Irg Soil Drain Pump N	14,313	757,468	75	190,840	0.0529
23	08LNX00002-MTHLY 80% GUAR		656			
24	08LNX00004-ANNUAL 80%GUAR		57,549			
25	08LNX00014-80% MIN MNTHLY		530			
26	08LNX00017-ADV/REF&80%ANN		108,202			
27	08LNX00152-AGR ANN GUAR M		844			
28	08LNX00300-LINE EXT 80% PLUS		28			
29	08LNX00310-IRR, 80% ANNUAL		3,023			
30	08LNX00312 IRG LINE EXT		3,369			
31	08NMT10135-IRR_SOIL DRNG NET	11	831	1	11,000	0.0755
32	08RFND 1999-RATE REFUND		1			
33	UNBILLED REVENUE	104	7,000			0.0673
34	WASHINGTON					
35	02APSV0040-AG PMP SRVC	143,928	8,647,963	4,663	30,866	0.0601
36	02APSV0040-AG PMP SRVC		-361,732			
37	02APSV040X-AG PMP SRVC	20,255	1,204,250	587	34,506	0.0595
38	02BPADEBIT-BPA ADJUST FEE		9,370			
39	02LNX00102-LINE EXT 80% G		957			
40	02LNX00103-LINE EXT 80% G		5,651			
41	TOTAL Billed	53,292,039	3,312,551,971	1,683,619	31,653	0.0622
42	Total Unbilled Rev.(See Instr. 6)	98,439	14,657,000	0	0	0.1489
43	TOTAL	53,390,478	3,327,208,971	1,683,619	31,712	0.0623

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1	02LNX00105-CNTRCT \$ MIN G		30			
2	02LNX00109-REF/NREF ADV +		1,951			
3	02LNX00110-REF/NREF ADV +		55,647			
4	02LNX00310-IRG 80% ANNUAL		429			
5	02LNX00312-IRG LINE EXT		145			
6	CENTRALIA RFND		10			
7	MERGER CREDITS		9			
8	BPA BALANCING ACCOUNT		338,962			
9	UNBILLED REVENUE	-209	-59,000			0.2823
10	WYOMING					
11	05APS00040-AG PUMPING SVC	16,704	1,238,994	563	29,670	0.0742
12	05LNX00110-REF/NREF ADV +		35,258			
13	05LNX00103-LINE EXT 80% G		5,757			
14	05LNX00310-LINE EXTENSION		274			
15	05LNX00312-IRG LINE EXT		364			
16	UNBILLED REVENUE	-7	-1,000			0.1429
17	05APS00040-AG PUMPING SVC		-3	1		
18	05LNX00103-LINE EXT 80% G		4,762			
19	05LNX00110-REF/NREF ADV +		4,093			
20	09APSV0210-IRR & SOIL DRA	3,095	196,037	50	61,900	0.0633
21	Less Multiple Billings			-609		
22						
23	IRRIGATION SALES TOTAL	1,458,632	87,383,463	22,790	64,003	0.0599
24						
25	PUBLIC STREET&HIGHWAY LIGHT					
26	CALIFORNIA					
27	06COSL0052-CO-OWND STR LG	8	6,104	5	1,600	0.7630
28	06CUSL053F-SPECIAL CUST O	1,466	156,620	120	12,217	0.1068
29	06CUSL058F-CUST OWND STR	251	30,524	23	10,913	0.1216
30	06HPSV0051-HI PRESSURE SO	681	147,184	75	9,080	0.2161
31	UNBILLED REVENUE	-9				
32	IDAHO					
33	07GNSV023S-TRAFFIC SIGNALS	94	9,107	26	3,615	0.0969
34	07SLCO0011-STR LGT CO-OWN	126	29,967	31	4,065	0.2378
35	07SLCU012E-ENGY STR LGT		146	1		
36	07SLCU012F-FULL MNT STR LGT	1,052	112,941	275	3,825	0.1074
37	07SCLU012P-PART MNT STR LGT	102	5,792	16	6,375	0.0568
38	07SLCU1201-TRAF SIGNAL SY	82	6,716	26	3,154	0.0819
39	07SLCU1203-STR LGT CUST-O		122	1		
40	07SLCU122A-STR LGT CUST-O	78	4,312	15	5,200	0.0553
41	TOTAL Billed	53,292,039	3,312,551,971	1,683,619	31,653	0.0622
42	Total Unbilled Rev.(See Instr. 6)	98,439	14,657,000	0	0	0.1489
43	TOTAL	53,390,478	3,327,208,971	1,683,619	31,712	0.0623

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1	07SLCU122B-STR LGT CUST-O	789	84,989	271	2,911	0.1077
2	UNBILLED REVENUE	-108	-11,000			0.1019
3	OREGON					
4	01COSL0052-STR LGT SRVC C	1,517	187,186	82	18,500	0.1234
5	01CUSL0053-CUS-OWND MTRD	749	50,469	63	11,889	0.0674
6	01CUSL053E-STR LGT SVC	4,685	317,175	97	48,299	0.0677
7	01CUSL053F-STR LGT SRVC C	3,459	245,159	86	40,221	0.0709
8	01HPSV0051-HI PRESSURE SO	16,161	3,022,033	672	24,049	0.1870
9	01MVSL0050-MERC VAPSTR LG	10,787	1,255,946	300	35,957	0.1164
10	01OALT014N-OUTD AR LGT NR		139	1		
11	01OALT014N-OUTD AR LGT NR		-2			
12	01OALT015N-OUTD AR LGT NR	5	898	2	2,500	0.1796
13	SB408 RECOVERY		-6,064			
14	SB838 RECOVERY		3,223			
15	UNBILLED REVENUE	258	51,000			0.1977
16	UTAH					
17	08CFR00012-STR LGTS (CONV		54			
18	08CFR00051-MTH FAC SRVCHG.		4,529			
19	08CFR00061-U/G AREA LIGHT		138			
20	08CFR00062-STREET LIGHTS		79			
21	08HAXT0060-LIGHTNG-HAXTON		93	1		
22	08OALT007N-SECURITY AR LG	1	223	2	500	0.2230
23	08SLC1202F-TRAFFIC SIG NM	1,183	81,275	130	9,100	0.0687
24	08SLCO0011-STR LGT CO-OWN	22,274	6,165,682	1,130	19,712	0.2768
25	08SLCU1202-TRAF & OTHER S	3,074	266,728	1,548	1,986	0.0868
26	08SLCU1203-MTR OUTDONIGHT	954	71,048	45	21,200	0.0745
27	08SLCU121A-STR LGT CUST-O	7,244	732,852	240	30,183	0.1012
28	08SLCU121B-STR LGT CUST-O	3,274	425,827	186	17,602	0.1301
29	08SLD13ES1-DECOR CUST-OWN	6,160	367,371	62	99,355	0.0596
30	08SLD13ES2-DECOR CUST-OWN	27,879	1,688,262	198	140,803	0.0606
31	08SLD13FS1-DECOR COMP-OWN	97	51,158	7	13,857	0.5274
32	08SLD13FS2-DECOR COMP-OWN	184	112,520	12	15,333	0.6115
33	08SLD13MS1-DECOR CUST-OWN	572	77,926	17	33,647	0.1362
34	08SLD13MS2-DECOR CUST-OWN	808	122,060	21	38,476	0.1511
35	08THIK0077-STR LIGHT SPEC	141	17,277	1	141,000	0.1225
36	UNBILLED REVENUE	-1,386	-167,000			0.1205
37	WASHINGTON					
38	02CFR00012-STR LGTS (CONV		91			
39	02COSL0052-STR LGT SRV	452	58,017	22	20,545	0.1284
40	02CUSL053F-STR LGT SRV	3,433	209,990	189	18,164	0.0612
41	TOTAL Billed	53,292,039	3,312,551,971	1,683,619	31,653	0.0622
42	Total Unbilled Rev.(See Instr. 6)	98,439	14,657,000	0	0	0.1489
43	TOTAL	53,390,478	3,327,208,971	1,683,619	31,712	0.0623

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1	02CUSL053M-STR LGT SRV	1,018	61,485	86	11,837	0.0604
2	02HPSV0051-HI PRESSURE	2,933	511,622	159	18,447	0.1744
3	02MVSL0057-MERC VAPSTR	2,059	218,907	51	40,373	0.1063
4	UNBILLED REVENUE	-28	-1,000			0.0357
5	WYOMING					
6	05COSL0057-CO-OWND STR LG	514	101,963	27	19,037	0.1984
7	05CUSL058F-CUST OWND STR	1,158	73,678	38	30,474	0.0636
8	05CUSL058M-CUST OWND STR	77	4,842	9	8,556	0.0629
9	05HPSV0051-HI PRESSURE SO	4,227	919,916	161	26,255	0.2176
10	05MVS00053-MERCURY VAPOR	4,137	530,299	269	15,379	0.1282
11	09SLCO0211-STR LGT CO-OWN	1	152	1	1,000	0.1520
12	09SLCU2122-TRAF & OTHER S	2	65	2	1,000	0.0325
13	UNBILLED REVENUE	-91	-14,000			0.1538
14	09SLCO0211-STR LGT CO-OWN	1,365	485,190	93	14,677	0.3555
15	09SLCU2121-STR LGT CUST-O	90	16,310	14	6,429	0.1812
16	09SLCU2122-TRAF & OTHER S	64	2,375	14	4,571	0.0371
17	UNBILLED REVENUE	-23	-6,000			0.2609
18	Less Multiple Billings			-2,693		
19						
20	Total PUBLIC STREET&HIGHWAY	136,080	18,902,690	4,230	32,170	0.1389
21						
22	OTHER SALES TO PUBLIC AUTH					
23	UTAH					
24	08GNSV0006-GEN SRVC-DISTR	2,336	143,834	4	584,000	0.0616
25	08GNSV0023-GEN SRVC-DISTR	27	2,319	2	13,500	0.0859
26	08GNSV009M-MANL HIGH VOLT	439,112	17,480,811	4	109,778,000	0.0398
27	08OALT007N-SECURITY AR LG	19	4,495	3	6,333	0.2366
28	UNBILLED REVENUE	-6,099	-122,000			0.0200
29						
30	Total Other Sales to Public Auth	435,395	17,509,459	13	33,491,923	0.0402
31						
32	FORFEITED DISCOUNTS					
33	CALIFORNIA					
34	Late Fees		205,977			
35	IDAHO					
36	Late Fees		368,666			
37	OREGON					
38	Late Fees		2,479,920			
39	UTAH					
40	Late Fees		2,744,745			
41	TOTAL Billed	53,292,039	3,312,551,971	1,683,619	31,653	0.0622
42	Total Unbilled Rev.(See Instr. 6)	98,439	14,657,000	0	0	0.1489
43	TOTAL	53,390,478	3,327,208,971	1,683,619	31,712	0.0623

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1	WASHINGTON					
2	Late Fees		484,516			
3	WYOMING					
4	Late Fees		430,589			
5	Late Fees		70,257			
6						
7	Total FORFEITED		6,784,670			
8						
9	OTHER ELECTRIC REVENUE					
10	CALIFORNIA					
11	06CFR00003-MTH MAINTENANC		1,454			
12	06CONN0300-RECONNECTION		102,787			
13	06METR0300-FEE MTR TES		200			
14	06FCBUYOUT		4,757			
15	06RCHK0300-RET CHK CHR		9,965			
16	06TAMP0300-TAMP & UNAU		2,325			
17	06TEMP0300-TEMP SRVC C		7,990			
18	06TRBL0300-TROUBLE CAL		30			
19	06SVRCHARG- EXCESS FOOTAGE		-2,018			
20	06XMTRTAMP-TAMPERING-UNAU		384			
21	Home Comfort		2,262			
22	Industrial Finanswer		771			
23	Irrigation Finanswer		992			
24	Other		7,054			
25	IDAHO					
26	07CFR00001-MTH FAC SRVCHG		2,100			
27	07CONN0300-RECONNECTION		83,820			
28	07RCHK0300-RET CHK CHR		23,620			
29	07TAMP0300		2,400			
30	07TEMP0014-TEMP SRVC CONN		27,205			
31	07XMTRTAMP-TAMPERING -		59			
32	Weatherization Loans		2,014			
33	Other		1,085			
34	OREGON					
35	01CFR00001-MTH FACILITY S		62,082			
36	01CFR00003-MTH MAINTENANC		26,061			
37	01CFR00004-EMRGNCY ST&BY		24,748			
38	01CFR00005-INTERMTNT SRVC		43,458			
39	01CFR00013-MTH MISC CHRG		2,284			
40	01CFR00014-YR MISC CHRG		5			
41	TOTAL Billed	53,292,039	3,312,551,971	1,683,619	31,653	0.0622
42	Total Unbilled Rev.(See Instr. 6)	98,439	14,657,000	0	0	0.1489
43	TOTAL	53,390,478	3,327,208,971	1,683,619	31,712	0.0623

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

- Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
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- For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
- Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	01CONN0300-RECONNECTION C		1,045,320			
2	01ESSC0600 -ESS charges		1,420			
3	01FCBUYOUT-FAC CHG BUYOUT		72,368			
4	01RCHK0300-RETURNED CHECK		221,350			
5	01TAMP0300-TAMP & UNAUTH		18,900			
6	01TEMP0300-TEMP SRVC CHRG		248,795			
7	01XMTRTAMP-TAMPERING -		3,271			
8	Other		22,891			
9	Retrofit Finanswer		1,017			
10	Misc Serv-Acct Serv Charge		411,681			
11	UTAH					
12	08CFR00013-MTH MISC CHRG		147,885			
13	08GNSV0006-GEN-SRVC-DISTR		15,663			
14	08CFR00051-MTH FAC SRVCHG		173,620			
15	08CFR00052-ANN FAC SVCCHG		424			
16	08CFR00053-MTHLY MAINTFEE		9,060			
17	08CFR00063-MTH MISC CHARG		3,301			
18	08CFR00064-ANN MISC CHARG		6,660			
19	08CONN0300-RECONN&DISCONN		517,300			
20	08CONTSERV-3RD PARTY O/S		207,351			
21	08FCBUYOUT-FAC CHG BUYOUT		97,038			
22	08MTRVR300 -Meter Verification F		510			
23	08NCON0300-FEE NRES RE3072		4,042			
24	08RCHK0300-RET CHK CHR		327,795			
25	08RCON0001-CONNECT FEE		1,688,160			
26	08TAMP0300-TAMPERING&UNAU		27,375			
27	08TEMP0014-TEMP SRVC CONN		724,570			
28	08XMTRTAMP-TAMPERING -		4,902			
29	08INFO0300-CUST/3RD P REQ		38			
30	Energy Finanswer 12,000		1,509			
31	Energy Finanswer new Com		69,718			
32	Other		-406,402			
33	08VISIT300 - Visit, Service Ca		323,665			
34	Retrofit Finanswer		478			
35	WASHINGTON					
36	02CFR00003-MTH MAINTENANC		1,320			
37	02CFR00004-EMRGNCY ST&BY		5,900			
38	02CFR00005-INTERMTNT SRVC		4,302			
39	02CONN0300-RECONNECTION		136,450			
40	02FCBUYOUT - FAC CHG BUYOUT		23,551			
41	TOTAL Billed	53,292,039	3,312,551,971	1,683,619	31,653	0.0622
42	Total Unbilled Rev.(See Instr. 6)	98,439	14,857,000	0	0	0.1489
43	TOTAL	53,390,478	3,327,208,971	1,683,619	31,712	0.0623

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SALES OF ELECTRICITY BY RATE SCHEDULES

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- For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
- Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	02RCHK0300-RET CHK CHR		40,405			
2	02TAMP0300-TAMP & UNAU		7,800			
3	02TEMP0300-TEMP SRVC C		41,765			
4	02XMTRTAMP-TAMPERING -		2,141			
5	Other		-1,718			
6	Weatherization Loans		106			
7	Energy Finanswer New Com		7,092			
8	Home Comfort		6,826			
9	WYOMING					
10	05CFR00003-MTH MAINTENANC		8,032			
11	05CFR00004-EMRGNCY ST&BY		20,576			
12	05CFR00005-INTERMTNT SRVC		10,554			
13	05CFR00013-MTH MISC CHRG		3,186			
14	05CONN0300-RECONNECTIO		78,470			
15	05FCBUYOUT-FAC CHG BUYOUT		142,224			
16	05RCHK0300-RET CHK CHR		44,700			
17	05SERV0300-SRVC CALLS		6,480			
18	05TEMP0300-TEMP SRVC		49,995			
19	09CFR00005-INTERMTNT SRVC		339			
20	05LONGFORM-BILL PRINT		40			
21	05CONN0300-RECONNECTION		10,180			
22	05FCBUYOUT - FAC CHG BUYOUT		111,064			
23	05RCHK0300-RET CHK CHR		6,300			
24	05SERV0300-SRVC CALLS		840			
25	05TAMP0300		1,200			
26	05TEMP0300- TEMP SRVC		6,035			
27	05XMTRTAMP-TAMPERING-UNAU		151			
28	09CFR00001-MTH FAC SRVCHG		5,366			
29	09CFR00014-YR MISC CHRG		2			
30	Energy Finanswer 12,000		493			
31	Other		1,509			
32						
33	MISC. SERVICE REV TOTAL		7,215,245			
34						
35	WATER & WATER PWR SALES					
36	UTAH		44,831			
37	WYOMING		62,649			
38						
39	Total WATER & WATER PWR		107,480			
40						
41	TOTAL Billed	53,292,039	3,312,551,971	1,683,619	31,653	0.0622
42	Total Unbilled Rev.(See Instr. 6)	98,439	14,657,000	0	0	0.1489
43	TOTAL	53,390,478	3,327,208,971	1,683,619	31,712	0.0623

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- For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
- Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RENT FROM ELEC PROPERTIES					
2	CALIFORNIA					
3	06CFR00006-MTH RNTAL CHRG		1,710			
4	RENT REVENUE-HYDRO		40,000			
5	Rent Revenue - Subleases		14,563			
6	Joint use		330,776			
7	IDAHO					
8	07CFR00009-YR LSE CHRG-EQ		794			
9	07INVCHG00-INVEST MNT CHG		181			
10	07LOOP0014-MTH FEE PRE-AS		2,247			
11	07POLE0075-STEEL POLES US		283			
12	07XTRN0013-RNT/LSE L& PRO		103,108			
13	RENT REVENUE-HYDRO		5,450			
14	Joint use		228,521			
15	Rents- Non common		300			
16	Rent Revenue - Subleases		554			
17	OREGON					
18	RENTS - COMMON		344,042			
19	Rents - Non Common		3,181			
20	MCI FOGWIRE REVENUE		3,351,126			
21	RENT REVENUE-HYDRO		-37,100			
22	RENT REV-TRANSMISS		204,919			
23	RENT REV-DISTRIBUT		6,957			
24	RENT REV-GEN(COMM)		45,521			
25	01CFR00006-MTH RNTAL CHRG		515,702			
26	01XTRN0013-RNT/LSE L&PRO		13,993			
27	Rent Revenue - Subleases		478,345			
28	Joint use		4,707,985			
29	UTAH					
30	08CFR00056-MTH EQUIP RENT		33			
31	08CFR00058-MTH EQUIP LEAS		729,283			
32	08INVCHG00N-INVEST MNT CHG		4,837			
33	08INVCHG00R-INVEST MNT CHG		328			
34	08LOOP014N-TEMP SERV CONN		15,288			
35	08POLE0004-POLE ATTACHMEN		5,190			
36	08POLE0075-STEEL POLES US		77,151			
37	08XTRN0013-RNT/LSE L& PRO		75,184			
38	RENTS - COMMON		-74,902			
39	Rents - Non Common		4,950			
40	RENT REVENUE-STEAM		36,280			
41	TOTAL Billed	53,292,039	3,312,551,971	1,683,619	31,653	0.0622
42	Total Unbilled Rev.(See Instr. 6)	98,439	14,657,000	0	0	0.1489
43	TOTAL	53,390,478	3,327,208,971	1,683,619	31,712	0.0623

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- For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
- Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RENT REVENUE-HYDRO		144,596			
2	RENT REV-TRANSMISS		819,706			
3	RENT REV-DISTRIBUT		83,346			
4	RENT REV-GEN(COMM)		550,012			
5	Rent Revenue - Subleases		1,959,100			
6	Joint use		2,160,770			
7	WASHINGTON					
8	02CFR00001-MTH FACILITY S		2,070			
9	02CFR00006-MTH RNTAL CHRG		35,573			
10	RENT REVENUE-HYDRO		665,811			
11	RENT REV-DISTRIBUT		14,190			
12	RENT REV-GEN(COMM)		30,649			
13	RENT REV-TRANSMISS		250			
14	Rent Revenue - Subleases		35,606			
15	Joint use		468,474			
16	WYOMING					
17	05CFR00001-MTH FACILITY S		11,524			
18	05CFR00006-MTH RNTAL CHRG		2,944			
19	RENT REVENUE-STEAM		38,377			
20	RENT REV-GEN(COMM)		13,893			
21	Rent Revenue - Subleases		51,647			
22	Joint use		390,815			
23	09LOOP0214-MTH FEE PRE-AS		159			
24	09POLE0075-STEEL POLES US		22,446			
25	RENT REVENUE-STEAM		5,388			
26	Joint use		16,633			
27						
28	Total RENT FROM ELEC		18,760,759			
29						
30	OTHER ELECTRIC REVENUE					
31	WYOMING					
32	ALL BLUE SKY RES		36,149			
33	ALL NON-RES BLUE SKY		4,798			
34	ALL BLUE SKY RES		4,423			
35	ALL NON-RES BLUE SKY		164			
36	WASHINGTON					
37	ALL BLUE SKY RES		37,093			
38	ALL NON-RES BLUE SKY		11,442			
39	UTAH					
40	ALL BLUE SKY RES		757,332			
41	TOTAL Billed	53,292,039	3,312,551,971	1,683,619	31,653	0.0622
42	Total Unbilled Rev.(See Instr. 6)	98,439	14,657,000	0	0	0.1489
43	TOTAL	53,390,478	3,327,208,971	1,683,619	31,712	0.0623

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- 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	ALL NON-RES BLUE SKY		193,265			
2	OREGON					
3	ALL BLUE SKY RES		123,149			
4	ALL NON-RES BLUE SKY		148,589			
5	IDAHO					
6	ALL BLUE SKY RES		13,316			
7	ALL NON-RES BLUE SKY		677			
8	CALIFORNIA					
9	ALL BLUE SKY RES		13,856			
10	ALL NON-RES BLUE SKY		359			
11	OTH ELEC ESTIMATE		-119,418			
12	GREEN CREDIT SALES		3,727,113			
13	NON-WHEELING SYSTEM REV		9,445,364			
14	ELEC INC- OTHR		16,310			
15	Other Elec		14,497,922			
16	DSM REV- CA SBC OFF		-27,462			
17	Joint Use Cust Accom		66,909			
18	CALIFORNIA					
19	Fish, Wildlife, Recr		3,899			
20	IDAHO					
21	DSM REV-ID SBC		2,048,020			
22	Other Elec		1,682			
23	OREGON					
24	3RD PARTY TRANS		441,088			
25	M&S INVENTORY REVENUE		12,108			
26	01XTRN0011- SALE ORDERS		22,851			
27	Joint Use Cust Accom		610,990			
28	Other Elec		3,074,563			
29	Other Elec DSR carry chrg		414,110			
30	UTAH					
31	ELEC INC-OTHR		230,006			
32	FLYASH SALES		309,944			
33	M&S INVENTORY REVENUE		981,968			
34	Joint Use Cust Accom		574			
35	DSM REV-UT SBC OFFSET		25,396,529			
36	Fish, Wildlife, Recr		1,960			
37	Other Elec		67,186			
38	WASHINGTON					
39	02XTRN0011-SALES ORDER INV		257			
40	Fish, Wildlife, Recr		53,553			
41	TOTAL Billed	53,292,039	3,312,551,971	1,683,619	31,653	0.0622
42	Total Unbilled Rev.(See Instr. 6)	98,439	14,657,000	0	0	0.1489
43	TOTAL	53,390,478	3,327,208,971	1,683,619	31,712	0.0623

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- For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
- Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Joint Use Cust Accom		97,043			
2	Wash Colstrip 3		-52,188			
3	WYOMING					
4	Joint Use Cust Accom		8,878			
5	ELEC INC-OTHR		463			
6	FLYASH SALES		2,534,613			
7	Regulatory Recovery Fee		176,496			
8	FLYASH SALES		11,765			
9						
10	OTHER ELECTRIC REVENUE		65,399,708			
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
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24						
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27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	53,292,039	3,312,551,971	1,683,619	31,653	0.0622
42	Total Unbilled Rev.(See Instr. 6)	98,439	14,657,000	0	0	0.1489
43	TOTAL	53,390,478	3,327,208,971	1,683,619	31,712	0.0623

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FOOTNOTE DATA			

Schedule Page: 304 Line No.: 42 Column: c

For further discussion on unbilled revenue refer to page 300, Electric Operating Revenues, line 12 column (b).

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(Next Page is 310)

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SALES FOR RESALE (Account 447) (Continued)

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

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

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

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

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)

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

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

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

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

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

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
					1
116,855	1,881,513	2,035,617		3,917,130	2
1,072	14,317	19,305		33,622	3
6,243	117,594	110,465		228,059	4
3,794	72,898	67,155		140,053	5
1,066	19,782	18,579		38,361	6
7,711	119,782	134,321		254,103	7
11,148		929,335	4,660	934,195	8
76,735	1,176,417	1,337,567		2,513,984	9
-14,929			-443,219	-443,219	10
					11
					12
8,491		458,346		458,346	13
			-12,195	-12,195	14
209,695	3,402,303	4,652,344	-438,359	7,616,288	
13,514,160	51,064,933	2,544,114,007	-1,745,930,397	849,248,543	
13,723,855	54,467,236	2,548,766,351	-1,746,368,756	856,864,831	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Arizona Public Service Co.	AD	T-12	NA	NA	NA
2	Arizona Public Service Co.	IF	T-12	NA	NA	NA
3	Arizona Public Service Co.	OS	T-12	NA	NA	NA
4	Arizona Public Service Co.	SF	T-12	NA	NA	NA
5	Avista Corp.	SF	T-13	NA	NA	NA
6	Avista Corp.	SF	WSPP	NA	NA	NA
7	Avista Energy, Inc.	SF	WSPP	NA	NA	NA
8	BP Energy Company	SF	WSPP	NA	NA	NA
9	Barclays Bank PLC	SF	T-12	NA	NA	NA
10	Basin Electric Power Cooperative	LF	T-11	NA	NA	NA
11	Basin Electric Power Cooperative	SF	T-11	NA	NA	NA
12	Basin Electric Power Cooperative	SF	WSPP	NA	NA	NA
13	Bear Energy LP	SF	T-12	NA	NA	NA
14	Benton County Public Utility Dist No. 1	SF	WSPP	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SALES FOR RESALE (Account 447) (Continued)

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

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

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

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

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

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

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

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

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

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
			139	139	1
25		993		993	2
1,877		102,128		102,128	3
222,722		13,078,701		13,078,701	4
56			2,792	2,792	5
42,995		2,309,125		2,309,125	6
88,129		4,300,460		4,300,460	7
1,929,254		122,854,492		122,854,492	8
2,543,522		147,527,015		147,527,015	9
3,848			210,491	210,491	10
897			45,329	45,329	11
32,553		2,047,405		2,047,405	12
561,767		33,722,094		33,722,094	13
5,597		255,874		255,874	14
209,695	3,402,303	4,652,344	-438,359	7,616,288	
13,514,160	51,064,933	2,544,114,007	-1,745,930,397	849,248,543	
13,723,855	54,467,236	2,548,766,351	-1,746,368,756	856,864,831	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SALES FOR RESALE (Account 447) (Continued)

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

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

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

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demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts.

Footnote any demand not stated on a megawatt basis and explain.

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

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

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

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

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
364,449	6,156,660	4,708,324		10,864,984	1
975		60,255		60,255	2
40,533		2,381,058		2,381,058	3
30		1,325		1,325	4
3,167	44,010	82,038		126,048	5
			29,065	29,065	6
5,053			86,258	86,258	7
2,887			133,369	133,369	8
36,316		1,452,277		1,452,277	9
177			12,886	12,886	10
130			6,848	6,848	11
142,145		7,835,520	10,199	7,825,321	12
231			13,709	13,709	13
89,507		4,824,520		4,824,520	14
209,695	3,402,303	4,652,344	-438,359	7,616,288	
13,514,160	51,064,933	2,544,114,007	-1,745,930,397	849,248,543	
13,723,855	54,467,236	2,548,766,351	-1,746,368,756	856,864,831	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/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 not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	California Independent System Operator	AD	T-12	NA	NA	NA
2	California Independent System Operator	SF	T-12	NA	NA	NA
3	Cargill Power Markets, LLC	AD	T-12	NA	NA	NA
4	Cargill Power Markets, LLC	OS	T-12	NA	NA	NA
5	Cargill Power Markets, LLC	SF	T-11	NA	NA	NA
6	Cargill Power Markets, LLC	SF	T-12	NA	NA	NA
7	Chelan County Public Utility Dist No. 1	SF	WSPP	NA	NA	NA
8	Citigroup Energy, Inc.	SF	T-11	NA	NA	NA
9	Citigroup Energy, Inc.	SF	T-12	NA	NA	NA
10	City of Roseville	SF	WSPP	NA	NA	NA
11	Clark Public Utilities	LF	T-12	NA	NA	NA
12	Clatskanie People's Utility District	SF	WSPP	NA	NA	NA
13	Colorado River Commission of Nevada	SF	WSPP	NA	NA	NA
14	Colorado Springs Utilities	SF	WSPP	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SALES FOR RESALE (Account 447) (Continued)

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

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

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

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

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

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

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

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

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

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
-200			-334,899	-334,899	1
233,982		11,532,545		11,532,545	2
253			14,386	14,386	3
47		1,551		1,551	4
31,387			1,685,773	1,685,773	5
2,299,753		136,879,828		136,879,828	6
1,800		89,000	1,200	90,200	7
65			4,828	4,828	8
1,731,458		107,176,758		107,176,758	9
261		17,505		17,505	10
384,000	853,237	14,643,120		15,496,357	11
1,566		69,851		69,851	12
24,607		983,556		983,556	13
381		24,081		24,081	14
209,695	3,402,303	4,652,344	-438,359	7,616,288	
13,514,160	51,064,933	2,544,114,007	-1,745,930,397	849,248,543	
13,723,855	54,467,236	2,548,766,351	-1,746,368,756	856,864,831	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SALES FOR RESALE (Account 447)

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Conoco Inc.	SF	T-11	NA	NA	NA
2	Conoco Inc.	SF	T-12	NA	NA	NA
3	Constellation Energy Commodities Group	OS	T-12	NA	NA	NA
4	Constellation Energy Commodities Group	SF	T-12	NA	NA	NA
5	Coral Power	SF	T-11	NA	NA	NA
6	Coral Power	SF	WSPP	NA	NA	NA
7	Credit Suisse Energy LLC	SF	T-12	NA	NA	NA
8	DB Energy Trading LLC	SF	T-12	NA	NA	NA
9	Douglas County Public Utility Dist No.1	SF	WSPP	NA	NA	NA
10	Dynegy Power Marketing	SF	WSPP	NA	NA	NA
11	EPCOR Energy Marketing (U.S.) Inc.	SF	WSPP	NA	NA	NA
12	El Paso Electric Company	SF	WSPP	NA	NA	NA
13	Eugene Water & Electric Board	SF	T-11	NA	NA	NA
14	Eugene Water & Electric Board	SF	WSPP	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SALES FOR RESALE (Account 447) (Continued)

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

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

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

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

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)

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

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

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

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

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

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h++j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
15			769	769	1
271,526		16,238,987		16,238,987	2
865		48,065		48,065	3
2,630,708		151,745,995		151,745,995	4
32			1,596	1,596	5
1,855,013		104,388,787		104,388,787	6
833,465		57,062,588		57,062,588	7
560,222		35,229,471		35,229,471	8
150		7,620		7,620	9
20		854		854	10
36,622		2,139,762		2,139,762	11
82,933		4,530,202		4,530,202	12
2,454			120,991	120,991	13
7,499		388,139		388,139	14
209,695	3,402,303	4,652,344	-438,359	7,616,288	
13,514,160	51,064,933	2,544,114,007	-1,745,930,397	849,248,543	
13,723,855	54,467,236	2,548,766,351	-1,746,368,756	856,864,831	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SALES FOR RESALE (Account 447) (Continued)

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

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

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

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

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

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

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

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

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

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
39,461		2,107,098		2,107,098	1
			-1,115	-1,115	2
611,531		36,840,410		36,840,410	3
1,823		88,550		88,550	4
142,559		6,984,114		6,984,114	5
45		2,025		2,025	6
29,239		1,808,831		1,808,831	7
4,772		247,042		247,042	8
2,800		180,800		180,800	9
12,799		359,970		359,970	10
1,102			79,036	79,036	11
26,983			1,539,080	1,539,080	12
820			40,862	40,862	13
494,763		27,709,225		27,709,225	14
209,695	3,402,303	4,652,344	-438,359	7,616,288	
13,514,160	51,064,933	2,544,114,007	-1,745,930,397	849,248,543	
13,723,855	54,467,236	2,548,766,351	-1,746,368,756	856,864,831	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SALES FOR RESALE (Account 447) (Continued)

- OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
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4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
31,181		1,882,860		1,882,860	1
1,431,692		74,871,392		74,871,392	2
78			402	402	3
			22	22	4
198,098		12,271,337		12,271,337	5
441,500		26,511,950		26,511,950	6
			-49,750	-49,750	7
583,940		25,976,563		25,976,563	8
94,392		4,709,722		4,709,722	9
251,986		15,548,914		15,548,914	10
56,497		3,211,430		3,211,430	11
647			39,130	39,130	12
4,645			234,533	234,533	13
8,809,871		479,594,598		479,594,598	14
209,695	3,402,303	4,652,344	-438,359	7,616,288	
13,514,160	51,064,933	2,544,114,007	-1,745,930,397	849,248,543	
13,723,855	54,467,236	2,548,766,351	-1,746,368,756	856,864,831	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Municipal Energy Agency of Nebraska	OS	WSPP	NA	NA	NA
2	Municipal Energy Agency of Nebraska	SF	T-11	NA	NA	NA
3	Municipal Energy Agency of Nebraska	SF	WSPP	NA	NA	NA
4	Nevada Power Company	SF	WSPP	NA	NA	NA
5	NorthWestern Energy	SF	T-13	NA	NA	NA
6	Northern California Power Agency	AD	WSPP	NA	NA	NA
7	Northern California Power Agency	SF	WSPP	NA	NA	NA
8	Northpoint Energy Solutions Inc.	SF	WSPP	NA	NA	NA
9	Occidental Power Services, Inc.	SF	WSPP	NA	NA	NA
10	PPL EnergyPlus, LLC	SF	WSPP	NA	NA	NA
11	PPL Montana, LLC	SF	T-11	NA	NA	NA
12	PPL Montana, LLC	SF	WSPP	NA	NA	NA
13	PPM Energy, Inc.	AD	T-11	NA	NA	NA
14	PPM Energy, Inc.	LF	T-11	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SALES FOR RESALE (Account 447) (Continued)

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

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

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

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

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)

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

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

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

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

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

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
110		3,090		3,090	1
50			2,272	2,272	2
13,433		881,433		881,433	3
125		5,000		5,000	4
785			41,999	41,999	5
			4	4	6
125,648		8,891,256		8,891,256	7
2,521		144,200		144,200	8
16,700		753,280		753,280	9
400		20,800		20,800	10
1,105			56,701	56,701	11
36,752		1,746,721		1,746,721	12
-9,765			-452,409	-452,409	13
59			629	629	14
209,695	3,402,303	4,652,344	-438,359	7,616,288	
13,514,160	51,064,933	2,544,114,007	-1,745,930,397	849,248,543	
13,723,855	54,467,236	2,548,766,351	-1,746,368,756	856,864,831	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SALES FOR RESALE (Account 447) (Continued)

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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.

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

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h++j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
23,052			978,489	978,489	1
679,043		35,897,506		35,897,506	2
137,068		7,510,073		7,510,073	3
11,168		566,990		566,990	4
388,559		21,134,175		21,134,175	5
10,080		516,440		516,440	6
96,850		6,693,450		6,693,450	7
55		3,025		3,025	8
156			6,692	6,692	9
507,887		30,392,216		30,392,216	10
240			13,567	13,567	11
12,306			611,872	611,872	12
10,000		645,000		645,000	13
23,105			1,185,313	1,185,313	14
209,695	3,402,303	4,652,344	-438,359	7,616,288	
13,514,160	51,064,933	2,544,114,007	-1,745,930,397	849,248,543	
13,723,855	54,467,236	2,548,766,351	-1,746,368,756	856,864,831	

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SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
1,795,086		93,450,260		93,450,260	1
			13,575	13,575	2
440			30,299	30,299	3
1,158,105	24,858,240	44,285,935		69,144,175	4
2,408			124,876	124,876	5
339,458		17,775,428		17,775,428	6
280		12,750		12,750	7
540,033		32,659,186		32,659,186	8
341			17,638	17,638	9
207,102		11,661,197		11,661,197	10
2,920			147,287	147,287	11
20,448		1,049,296		1,049,296	12
42,682		3,269,667		3,269,667	13
6,400		367,050		367,050	14
209,695	3,402,303	4,652,344	-438,359	7,616,288	
13,514,160	51,064,933	2,544,114,007	-1,745,930,397	849,248,543	
13,723,855	54,467,236	2,548,766,351	-1,746,368,756	856,864,831	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SALES FOR RESALE (Account 447)

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	SUEZ Energy Marketing NA, Inc.	SF	WSPP	NA	NA	NA
2	Sacramento Municipal Utility District	AD	250	NA	NA	NA
3	Sacramento Municipal Utility District	LF	250	NA	NA	NA
4	Sacramento Municipal Utility District	SF	WSPP	NA	NA	NA
5	Salt River Project	IF	WSPP	NA	NA	NA
6	Salt River Project	SF	WSPP	NA	NA	NA
7	San Diego Gas & Electric	SF	WSPP	NA	NA	NA
8	Santa Clara, City of	SF	WSPP	NA	NA	NA
9	Seattle City Light	SF	T-13	NA	NA	NA
10	Seattle City Light	SF	WSPP	NA	NA	NA
11	Sempra Energy Solutions	SF	WSPP	NA	NA	NA
12	Sempra Energy Trading LLC	AD	T-12	NA	NA	NA
13	Sempra Energy Trading LLC	SF	T-11	NA	NA	NA
14	Sempra Energy Trading LLC	SF	T-12	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SALES FOR RESALE (Account 447) (Continued)

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

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

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

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

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

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

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

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

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

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
82,769		4,382,616		4,382,616	1
			816,442	816,442	2
569,406		11,906,279		11,906,279	3
180,597		8,691,353		8,691,353	4
219,000		11,761,320		11,761,320	5
233,470		12,137,047		12,137,047	6
5,395		290,123		290,123	7
37,859		2,161,763		2,161,763	8
39			1,684	1,684	9
28,442		1,382,975		1,382,975	10
44,625		2,273,788		2,273,788	11
151			8,804	8,804	12
1,724			95,392	95,392	13
4,400,984		268,076,061		268,076,061	14
209,695	3,402,303	4,652,344	-438,359	7,616,288	
13,514,160	51,064,933	2,544,114,007	-1,745,930,397	849,248,543	
13,723,855	54,467,236	2,548,766,351	-1,746,368,756	856,864,831	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SALES FOR RESALE (Account 447)

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Sempra Generation	SF	T-12	NA	NA	NA
2	Sierra Pacific Power Company	AD	258	NA	NA	NA
3	Sierra Pacific Power Company	LF	258	75	75	72
4	Sierra Pacific Power Company	LF	T-11	NA	NA	NA
5	Sierra Pacific Power Company	SF	T-11	NA	NA	NA
6	Sierra Pacific Power Company	SF	T-13	NA	NA	NA
7	Sierra Pacific Power Company	SF	WSPP	NA	NA	NA
8	Snohomish Public Utility District No. 1	SF	WSPP	NA	NA	NA
9	Southern California Edison Company	SF	T-12	NA	NA	NA
10	Southwestern Public Service Company	SF	WSPP	NA	NA	NA
11	State of CA Dept of Water Resources	SF	WSPP	NA	NA	NA
12	Tacoma, City of	SF	WSPP	NA	NA	NA
13	The Energy Authority	SF	WSPP	NA	NA	NA
14	TransAlta Energy Marketing Inc.	IF	T-12	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SALES FOR RESALE (Account 447) (Continued)

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

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

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

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

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

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

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

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

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

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h++j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
39,498		1,805,040		1,805,040	1
			-1,635,525	-1,635,525	2
460,297	15,057,000	16,566,089		31,623,089	3
1,021			51,589	51,589	4
40,241			2,381,839	2,381,839	5
154			8,866	8,866	6
152,617		9,735,844		9,735,844	7
45,095		2,427,490		2,427,490	8
31,085		1,926,887		1,926,887	9
22,483		1,117,470		1,117,470	10
13,400		809,856		809,856	11
1,735		78,490		78,490	12
400		14,400		14,400	13
552,125		31,094,951		31,094,951	14
209,695	3,402,303	4,652,344	-438,359	7,616,288	
13,514,160	51,064,933	2,544,114,007	-1,745,930,397	849,248,543	
13,723,855	54,467,236	2,548,766,351	-1,746,368,756	856,864,831	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	04/03/2008	End of 2007/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 not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows: RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

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

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

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

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

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	TransAlta Energy Marketing Inc.	SF	T-12	NA	NA	NA
2	TransAlta Energy Marketing Inc.	SF	WSPP	NA	NA	NA
3	Tri-State Generation & Transmission	AD	WSPP	NA	NA	NA
4	Tri-State Generation & Transmission	SF	T-11	NA	NA	NA
5	Tri-State Generation & Transmission	SF	WSPP	0.7	0.7	0.1
6	Tucson Electric Power	SF	WSPP	NA	NA	NA
7	Turlock Irrigation District	SF	WSPP	NA	NA	NA
8	UBS Warburg Energy LLC	AD	T-12	NA	NA	NA
9	UBS Warburg Energy LLC	SF	T-12	NA	NA	NA
10	Utah Associated Municipal Power Systems	IU	WSPP	NA	NA	NA
11	Utah Associated Municipal Power Systems	OS	WSPP	NA	NA	NA
12	Utah Associated Municipal Power Systems	SF	WSPP	NA	NA	NA
13	Utah Municipal Power Agency	LF	433	31	31	31
14	Utah Municipal Power Agency	SF	T-3	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SALES FOR RESALE (Account 447) (Continued)

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

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

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

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

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)

demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts.

Footnote any demand not stated on a megawatt basis and explain.

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

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

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

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

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
93,765		5,173,138		5,173,138	1
84,638		4,523,988		4,523,988	2
25			1,700	1,700	3
1,595			76,797	76,797	4
109,162	33,611	6,537,437		6,571,048	5
266,957		16,941,386		16,941,386	6
6,200		343,800		343,800	7
			-3	-3	8
1,170,471		71,731,652		71,731,652	9
14,575		553,850		553,850	10
2,935		117,475		117,475	11
5,662		442,552		442,552	12
203,705	4,062,175	4,734,104		8,796,279	13
8,546		516,670		516,670	14
209,695	3,402,303	4,652,344	-438,359	7,616,288	
13,514,160	51,064,933	2,544,114,007	-1,745,930,397	849,248,543	
13,723,855	54,467,236	2,548,766,351	-1,746,368,756	856,864,831	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	04/03/2008	End of <u>2007/Q4</u>

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).

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	Western Area Power Administration	OS	WSPP	NA	NA	NA
2	Western Area Power Administration	SF	T-11	NA	NA	NA
3	Western Area Power Administration	SF	WSPP	NA	NA	NA
4	Bookouts	AD	NA	NA	NA	NA
5	Bookouts	SF	NA	NA	NA	NA
6	Test Generation	OS	NA	NA	NA	NA
7	Trading	SF	NA	NA	NA	NA
8	Accrual True-up	NA	NA	NA	NA	NA
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SALES FOR RESALE (Account 447) (Continued)

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

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

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

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

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

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

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

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

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

MegaWatt Hours Sold (g)	REVENUE			Total (\$ (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
20		760		760	1
257			12,889	12,889	2
174,244		11,414,883		11,414,883	3
-731			-76,136	-76,136	4
-32,163,253			-1,424,201,264	-1,424,201,264	5
-241,471			-14,638,049	-14,638,049	6
			-315,043,007	-315,043,007	7
17,610			-466,555	-466,555	8
					9
					10
					11
					12
					13
					14
209,695	3,402,303	4,652,344	-438,359	7,616,288	
13,514,160	51,064,933	2,544,114,007	-1,745,930,397	849,248,543	
13,723,855	54,467,236	2,548,766,351	-1,746,368,756	856,864,831	

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 310 Line No.: 8 Column: j

Settlement Adjustment

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

Represents the difference between actual requirement sales revenues for the period as reflected on the individual line items within this schedule, and the accruals charged to account 447 during the period.

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

Settlement Adjustment

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

Settlement Adjustment

Schedule Page: 310.1 Line No.: 1 Column: b

Settlement Adjustment

Schedule Page: 310.1 Line No.: 1 Column: j

Settlement Adjustment

Schedule Page: 310.1 Line No.: 2 Column: b

Arizona Public Service Co. - FERC T-12 - Contract termination date: December 31, 2006.

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

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.1 Line No.: 5 Column: j

Reserve Share

Schedule Page: 310.1 Line No.: 10 Column: b

Basin Electric Power Company - FERC T-11 [Evergreen Network Transmission Service under the Open Access Transmission Tariff (S.A. 228 & 233)] - Contract termination date: 12 months notification.

Schedule Page: 310.1 Line No.: 10 Column: j

Transmission Losses

Schedule Page: 310.1 Line No.: 11 Column: j

Transmission Losses

Schedule Page: 310.2 Line No.: 1 Column: b

Black Hills Power & Light Company - FERC 441 - Contract termination date: December 31, 2023.

Schedule Page: 310.2 Line No.: 2 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.2 Line No.: 5 Column: b

Blanding City - FERC T-12 - Contract termination date: March 1, 2007.

Schedule Page: 310.2 Line No.: 6 Column: b

Settlement Adjustment

Schedule Page: 310.2 Line No.: 6 Column: j

Settlement Adjustment

Schedule Page: 310.2 Line No.: 7 Column: b

Bonneville Power Administration - FERC 368 [Use of Facilities Agreement for the Malin Transformer under the AC Intertie Agreement with BPA] - Contract termination date: Upon mutual agreement.

Schedule Page: 310.2 Line No.: 7 Column: j

Transmission Losses

Schedule Page: 310.2 Line No.: 8 Column: b

Bonneville Power Administration - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 179)] - Contract termination date: September 30, 2025.

Schedule Page: 310.2 Line No.: 8 Column: j

Transmission Losses

Schedule Page: 310.2 Line No.: 9 Column: b

Bonneville Power Administration - FERC T-12 - Contract termination date: April 22, 2024.

Schedule Page: 310.2 Line No.: 10 Column: j

Transmission Losses

Schedule Page: 310.2 Line No.: 11 Column: j

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Reserve Share

Schedule Page: 310.2 Line No.: 12 Column: j

Liquidated Damages

Schedule Page: 310.2 Line No.: 13 Column: j

Reserve Share

Schedule Page: 310.3 Line No.: 1 Column: b

Settlement Adjustment

Schedule Page: 310.3 Line No.: 1 Column: j

Settlement Adjustment

Schedule Page: 310.3 Line No.: 3 Column: b

Settlement Adjustment

Schedule Page: 310.3 Line No.: 3 Column: j

Settlement Adjustment

Schedule Page: 310.3 Line No.: 4 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.3 Line No.: 5 Column: j

Transmission Losses

Schedule Page: 310.3 Line No.: 7 Column: j

Pond Sale

Schedule Page: 310.3 Line No.: 8 Column: j

Transmission Losses

Schedule Page: 310.3 Line No.: 11 Column: b

Clark County PUD #1 - FERC T-12 - Contract termination date: December 12, 2007.

Schedule Page: 310.4 Line No.: 1 Column: j

Transmission Losses

Schedule Page: 310.4 Line No.: 3 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.4 Line No.: 5 Column: j

Transmission Losses

Schedule Page: 310.4 Line No.: 13 Column: j

Transmission Losses

Schedule Page: 310.5 Line No.: 2 Column: b

Settlement Adjustment.

Schedule Page: 310.5 Line No.: 2 Column: j

Settlement Adjustment

Schedule Page: 310.5 Line No.: 10 Column: b

Hurricane, City of - FERC T-12 - Contract termination date: August 31, 2007.

Schedule Page: 310.5 Line No.: 11 Column: b

Idaho Power Company - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 212)] - Contract termination date: May 31, 2009.

Schedule Page: 310.5 Line No.: 11 Column: j

Transmission Losses

Schedule Page: 310.5 Line No.: 12 Column: j

Transmission Losses

Schedule Page: 310.5 Line No.: 13 Column: j

Reserve Share

Schedule Page: 310.6 Line No.: 3 Column: b

Settlement Adjustment.

Schedule Page: 310.6 Line No.: 3 Column: j

Settlement Adjustment

Schedule Page: 310.6 Line No.: 4 Column: j

Transmission Losses

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 310.6 Line No.: 7 Column: b

Settlement Adjustment.

Schedule Page: 310.6 Line No.: 7 Column: j

Settlement Adjustment

Schedule Page: 310.6 Line No.: 8 Column: b

Los Angeles Department of Water and Power - FERC 301 - Contract termination date: June 15, 2027.

Schedule Page: 310.6 Line No.: 12 Column: b

Settlement Adjustment.

Schedule Page: 310.6 Line No.: 12 Column: j

Settlement Adjustment

Schedule Page: 310.6 Line No.: 13 Column: j

Transmission Losses

Schedule Page: 310.7 Line No.: 1 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.7 Line No.: 2 Column: j

Transmission Losses

Schedule Page: 310.7 Line No.: 5 Column: j

Reserve Share

Schedule Page: 310.7 Line No.: 6 Column: b

Settlement Adjustment.

Schedule Page: 310.7 Line No.: 6 Column: j

Settlement Adjustment

Schedule Page: 310.7 Line No.: 11 Column: j

Transmission Losses

Schedule Page: 310.7 Line No.: 13 Column: b

Settlement Adjustment.

Schedule Page: 310.7 Line No.: 13 Column: j

Settlement Adjustment

Schedule Page: 310.7 Line No.: 14 Column: b

PPM Energy, Inc. - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 279)] - Contract termination date: April 30, 2008.

Schedule Page: 310.7 Line No.: 14 Column: j

Transmission Losses

Schedule Page: 310.8 Line No.: 1 Column: j

Transmission Losses

Schedule Page: 310.8 Line No.: 8 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.8 Line No.: 9 Column: j

Transmission Losses

Schedule Page: 310.8 Line No.: 11 Column: j

Reserve Share

Schedule Page: 310.8 Line No.: 12 Column: b

PowerEX - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 169)] - Contract termination date: September 30, 2008.

Schedule Page: 310.8 Line No.: 12 Column: j

Transmission Losses

Schedule Page: 310.8 Line No.: 13 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.8 Line No.: 14 Column: j

Transmission Losses

Schedule Page: 310.9 Line No.: 2 Column: b

Settlement Adjustment.

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 310.9 Line No.: 2 Column: j

Settlement Adjustment

Schedule Page: 310.9 Line No.: 3 Column: b

Settlement Adjustment.

Schedule Page: 310.9 Line No.: 3 Column: j

Settlement Adjustment

Schedule Page: 310.9 Line No.: 4 Column: b

Public Service Company of Colorado - FERC 320 - Contract termination date: December 31, 2011.

Schedule Page: 310.9 Line No.: 5 Column: j

Transmission Losses

Schedule Page: 310.9 Line No.: 7 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.9 Line No.: 9 Column: j

Reserve Share

Schedule Page: 310.9 Line No.: 11 Column: j

Transmission Losses

Schedule Page: 310.10 Line No.: 2 Column: b

Settlement Adjustment.

Schedule Page: 310.10 Line No.: 2 Column: j

Settlement Adjustment

Schedule Page: 310.10 Line No.: 3 Column: b

Sacramento Municipal Utility District - FERC 250 - Contract termination date: December 31, 2014.

Schedule Page: 310.10 Line No.: 5 Column: b

Salt River Project - WSPP - Contract termination date: December 31, 2009.

Schedule Page: 310.10 Line No.: 9 Column: j

Reserve Share

Schedule Page: 310.10 Line No.: 12 Column: b

Settlement Adjustment.

Schedule Page: 310.10 Line No.: 12 Column: j

Settlement Adjustment

Schedule Page: 310.10 Line No.: 13 Column: j

Transmission Losses

Schedule Page: 310.11 Line No.: 2 Column: b

Settlement Adjustment.

Schedule Page: 310.11 Line No.: 2 Column: j

Settlement Adjustment

Schedule Page: 310.11 Line No.: 3 Column: b

Sierra Pacific Power Company - FERC 258 - Contract termination date: February 28, 2009.

Schedule Page: 310.11 Line No.: 4 Column: b

Sierra Pacific Power Company - FERC T-11 [Pavant Capacitor Ownership, Operation and Maintenance Letter Agreement dated November 9, 2000] - Contract termination date: 90 days notification.

Schedule Page: 310.11 Line No.: 4 Column: j

Transmission Losses

Schedule Page: 310.11 Line No.: 5 Column: j

Transmission Losses

Schedule Page: 310.11 Line No.: 6 Column: j

Reserve Share

Schedule Page: 310.11 Line No.: 14 Column: b

TransAlta Energy Marketing Inc. - FERC T-12 - Contract termination date: December 31, 2010.

Schedule Page: 310.12 Line No.: 3 Column: b

Settlement Adjustment.

Schedule Page: 310.12 Line No.: 3 Column: j

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Settlement Adjustment

Schedule Page: 310.12 Line No.: 4 Column: j

Transmission Losses

Schedule Page: 310.12 Line No.: 8 Column: b

Settlement Adjustment.

Schedule Page: 310.12 Line No.: 8 Column: j

Settlement Adjustment

Schedule Page: 310.12 Line No.: 10 Column: b

Utah Associated Municipal Power Systems - WSPP - Contract termination date: October 31, 2007.

Schedule Page: 310.12 Line No.: 11 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.12 Line No.: 13 Column: b

Utah Municipal Power Agency - FERC 433 - Contract termination date: June 30, 2017.

Schedule Page: 310.13 Line No.: 1 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.13 Line No.: 2 Column: j

Transmission Losses

Schedule Page: 310.13 Line No.: 4 Column: b

Settlement Adjustment.

Schedule Page: 310.13 Line No.: 4 Column: j

Settlement Adjustment

Schedule Page: 310.13 Line No.: 5 Column: j

Recognition of revenue and gains on transactions that were bookout under EITF Issue No. 03-11.

Schedule Page: 310.13 Line No.: 6 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.13 Line No.: 6 Column: j

The negative revenue reported on this line reflects test energy generated at the Marengo Wind, Lakeside, Blundell 2 and Goodnoe Hills power plants that were transferred to construction. Energy generated during testing was delivered to PacifiCorp's electric system for sale, as required by the guidance in 18 CFR Electric Plant Instructions 18(a), is a component of construction and is the fair value of the energy delivered.

Schedule Page: 310.13 Line No.: 7 Column: j

Recognition of gains and losses on energy trading contracts under EITF Issue No. 02-03.

Schedule Page: 310.13 Line No.: 8 Column: j

Represents the difference between actual nonrequirement sales revenues for the period as reflected on the individual line items within this schedule, and the accruals charged to account 447 during the period.

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(Next Page is 320)

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/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	21,506,117	22,686,191	
5	(501) Fuel	581,178,395	485,079,578	
6	(502) Steam Expenses	33,767,391	32,320,388	
7	(503) Steam from Other Sources	4,845,079	3,110,724	
8	(Less) (504) Steam Transferred-Cr.			
9	(505) Electric Expenses	4,007,896	4,215,404	
10	(506) Miscellaneous Steam Power Expenses	41,844,589	30,690,672	
11	(507) Rents	859,203	1,173,471	
12	(509) Allowances			
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	688,008,670	579,276,428	
14	Maintenance			
15	(510) Maintenance Supervision and Engineering	6,200,007	7,604,360	
16	(511) Maintenance of Structures	22,514,293	19,475,953	
17	(512) Maintenance of Boiler Plant	94,470,112	90,246,837	
18	(513) Maintenance of Electric Plant	31,838,656	32,506,692	
19	(514) Maintenance of Miscellaneous Steam Plant	11,951,367	11,617,137	
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	166,974,435	161,450,979	
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	854,983,105	740,727,407	
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	8,428,491	7,448,958	
45	(536) Water for Power	216,788	241,545	
46	(537) Hydraulic Expenses	4,705,966	4,629,403	
47	(538) Electric Expenses		3,787	
48	(539) Miscellaneous Hydraulic Power Generation Expenses	13,992,399	15,883,249	
49	(540) Rents	45,426	94,633	
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	27,389,070	28,301,575	
51	C. Hydraulic Power Generation (Continued)			
52	Maintenance			
53	(541) Maintenance Supervision and Engineering			
54	(542) Maintenance of Structures	1,020,921	1,072,249	
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,017,895	1,435,262	
56	(544) Maintenance of Electric Plant	1,678,495	948,267	
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,107,860	2,543,440	
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	5,825,171	5,999,218	
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	33,214,241	34,300,793	

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/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	729,753	1,170,218		
63	(547) Fuel	325,837,509	129,693,593		
64	(548) Generation Expenses	22,455,638	12,202,052		
65	(549) Miscellaneous Other Power Generation Expenses	5,931,466	2,930,812		
66	(550) Rents	11,964,686	13,642,417		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	366,919,052	159,639,092		
68	Maintenance				
69	(551) Maintenance Supervision and Engineering				
70	(552) Maintenance of Structures	615,974	239,024		
71	(553) Maintenance of Generating and Electric Plant	4,630,669	2,562,314		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	396,083	436,088		
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	5,642,726	3,237,426		
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	372,561,778	162,876,518		
75	E. Other Power Supply Expenses				
76	(555) Purchased Power	763,738,961	707,454,156		
77	(556) System Control and Load Dispatching	2,535,080	2,484,435		
78	(557) Other Expenses	60,542,623	54,585,469		
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	826,816,664	764,524,060		
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	2,087,575,788	1,702,428,778		
81	2. TRANSMISSION EXPENSES				
82	Operation				
83	(560) Operation Supervision and Engineering	8,207,350	7,758,555		
84	(561) Load Dispatching		1,087,335		
85	(561.1) Load Dispatch-Reliability				
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	6,335,813	4,161,724		
87	(561.3) Load Dispatch-Transmission Service and Scheduling				
88	(561.4) Scheduling, System Control and Dispatch Services				
89	(561.5) Reliability, Planning and Standards Development				
90	(561.6) Transmission Service Studies	594,239	805,928		
91	(561.7) Generation Interconnection Studies	958,694	507,258		
92	(561.8) Reliability, Planning and Standards Development Services				
93	(562) Station Expenses	1,006,028	320,015		
94	(563) Overhead Lines Expenses	125,807	2,320,087		
95	(564) Underground Lines Expenses				
96	(565) Transmission of Electricity by Others	106,592,111	94,110,633		
97	(566) Miscellaneous Transmission Expenses	2,751,804	938,870		
98	(567) Rents	1,356,267	1,343,348		
99	TOTAL Operation (Enter Total of lines 83 thru 98)	127,928,113	113,353,753		
100	Maintenance				
101	(568) Maintenance Supervision and Engineering	56,234	19,767		
102	(569) Maintenance of Structures	4,076	5,318		
103	(569.1) Maintenance of Computer Hardware	8,331			
104	(569.2) Maintenance of Computer Software	704,405	132,256		
105	(569.3) Maintenance of Communication Equipment	2,516,755	1,820,947		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant				
107	(570) Maintenance of Station Equipment	9,272,545	10,062,229		
108	(571) Maintenance of Overhead Lines	13,323,841	10,812,758		
109	(572) Maintenance of Underground Lines				
110	(573) Maintenance of Miscellaneous Transmission Plant	380,572	723,453		
111	TOTAL Maintenance (Total of lines 101 thru 110)	26,266,759	23,576,728		
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	154,194,872	136,930,481		

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)					
If the amount for previous year is not derived from previously reported figures, explain in footnote.					
Line No.	Account (a)	Amount for Current Year (b)		Amount for Previous Year (c)	
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES				
166	Operation				
167	(907) Supervision	423,543		1,301,809	
168	(908) Customer Assistance Expenses	42,756,237		47,710,915	
169	(909) Informational and Instructional Expenses	3,784,546		3,620,675	
170	(910) Miscellaneous Customer Service and Informational Expenses	5,126		105,971	
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	46,969,452		52,739,370	
172	7. SALES EXPENSES				
173	Operation				
174	(911) Supervision				
175	(912) Demonstrating and Selling Expenses				
176	(913) Advertising Expenses				
177	(916) Miscellaneous Sales Expenses				
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)				
179	8. ADMINISTRATIVE AND GENERAL EXPENSES				
180	Operation				
181	(920) Administrative and General Salaries	83,301,566		142,943,825	
182	(921) Office Supplies and Expenses	11,779,729		10,053,431	
183	(Less) (922) Administrative Expenses Transferred-Credit	20,697,804		23,386,081	
184	(923) Outside Services Employed	9,800,219		18,460,427	
185	(924) Property Insurance	24,516,013		23,392,399	
186	(925) Injuries and Damages	11,291,287		10,053,945	
187	(926) Employee Pensions and Benefits				
188	(927) Franchise Requirements				
189	(928) Regulatory Commission Expenses	10,011,639		8,435,094	
190	(929) (Less) Duplicate Charges-Cr.	5,845,340		9,571,778	
191	(930.1) General Advertising Expenses	257,282		1,693,669	
192	(930.2) Miscellaneous General Expenses	25,310,886		25,696,241	
193	(931) Rents	6,292,505		8,197,293	
194	TOTAL Operation (Enter Total of lines 181 thru 193)	156,017,982		215,968,465	
195	Maintenance				
196	(935) Maintenance of General Plant	24,338,489		22,676,043	
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	180,356,471		238,644,508	
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	2,785,895,241		2,457,427,890	

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 320 Line No.: 187 Column: b

Pensions and benefits are charged to functional accounts, which is consistent to where labor is charged. The following table summarizes the pension and benefit expense that was charged to the functional accounts.

Twelve Months Ending December 31,		
	2007	2006
Pension & Benefits Expense	\$ 170,449,274	\$ 172,724,970

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Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Power Purchases					
2	3Degrees	SF		NA	NA	NA
3	AES SeaWest, Inc.	AD		NA	NA	NA
4	AES SeaWest, Inc.	LU		NA	NA	NA
5	Alberta Power Pool	SF		NA	NA	NA
6	American Electric Power	SF		NA	NA	NA
7	Anaheim, City of	OS		NA	NA	NA
8	Anaheim, City of	SF		NA	NA	NA
9	Arizona Electric Power Cooperative	SF		NA	NA	NA
10	Arizona Public Service Co.	IF		NA	NA	NA
11	Arizona Public Service Co.	LF		NA	NA	NA
12	Arizona Public Service Co.	SF		NA	NA	NA
13	Avista Corp.	OS		NA	NA	NA
14	Avista Corp.	SF		NA	NA	NA
	Total					

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
							1
					437,500	437,500	2
					-549,100	-549,100	3
140,903				4,999,238		4,999,238	4
118					6,010	6,010	5
48				2,160		2,160	6
5,435				121,785		121,785	7
9,771				403,705		403,705	8
42				2,010		2,010	9
227,850				14,785,127		14,785,127	10
174,340				5,868,566		5,868,566	11
64,676				3,148,010		3,148,010	12
					5,500	5,500	13
42,578				2,217,945	24,817	2,242,762	14
13,186,772	9,646,444	8,978,368	121,808,550	2,308,732,360	-1,666,801,949	763,738,961	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Avista Energy, Inc.	OS		NA	NA	NA
2	Avista Energy, Inc.	SF		NA	NA	NA
3	BP Energy Company	SF		NA	NA	NA
4	Ballard Hog Farms Inc.	LU		NA	NA	NA
5	Barclays Bank PLC	SF		NA	NA	NA
6	Bear Energy LP	SF		NA	NA	NA
7	Beaver City	LF		NA	NA	NA
8	Bell Mountain Power	LU		NA	NA	NA
9	Benton County Pub Utility Dist No. 1	SF		NA	NA	NA
10	Biomass One, L.P.	LU		22.5	17.7	15.1
11	Birch Creek Hydro	LU		NA	NA	NA
12	Black Hills Power, Inc.	AD		NA	NA	NA
13	Black Hills Power, Inc.	LU		NA	NA	NA
14	Black Hills Power, Inc.	OS		NA	NA	NA
Total						

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555) (Continued)
(including power exchanges)

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

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

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

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

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
					2,200	2,200	1
112,589				5,578,631		5,578,631	2
1,376,946				82,578,363	803,333	83,381,696	3
5				138		138	4
1,962,037				111,420,974	593,779	112,014,753	5
664,953				37,543,282	1,469,330	39,012,612	6
63				5,279		5,279	7
1,090				52,027		52,027	8
11,673				615,532		615,532	9
127,003			2,399,625	16,482,858	4,661,275	23,543,758	10
11,936				625,950		625,950	11
-2					83,287	83,287	12
4,331					1,227,106	1,227,106	13
8				400		400	14
13,186,772	9,646,444	8,978,368	121,808,550	2,308,732,360	-1,666,801,949	763,738,961	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
82,218				5,211,620		5,211,620	1
6,669				289,495		289,495	2
268				20,066		20,066	3
111					3,610	3,610	4
1,148				38,088		38,088	5
					-538,216	-538,216	6
			47,058,000			47,058,000	7
					1,464,834	1,464,834	8
					1,018,608	1,018,608	9
					18,180	18,180	10
681,906				27,569,095	266,035	27,835,130	11
157					7,996	7,996	12
-8					-206	-206	13
54,530				3,274,468		3,274,468	14
13,186,772	9,646,444	8,978,368	121,808,550	2,308,732,360	-1,666,801,949	763,738,961	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
20,725				1,081,780		1,081,780	1
-66					1,652	1,652	2
389,908				20,295,359		20,295,359	3
633					34,395	34,395	4
2,712,325				165,381,213		165,381,213	5
25,102			433,444	2,186,361		2,619,805	6
					161,558	161,558	7
389,371					3,809,685	3,809,685	8
					400	400	9
51,782				2,321,730	9,634	2,331,364	10
1,697,605				97,616,474	159,674	97,776,148	11
1,598			26,125	111,832		137,957	12
2,480				131,690		131,690	13
51,107				2,805,148		2,805,148	14
13,186,772	9,646,444	8,978,368	121,808,550	2,308,732,360	-1,666,801,949	763,738,961	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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**PURCHASED POWER (Account 555)
(Including power exchanges)**

- 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.
- 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.
- In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Colorado Springs Utilities	SF		NA	NA	NA
2	Columbia Storage Power Exchange	AD		NA	NA	NA
3	Commercial Energy Management	LU		NA	NA	NA
4	Conoco Inc.	OS		NA	NA	NA
5	Conoco Inc.	SF		NA	NA	NA
6	Constellation Energy Commodities Group	OS		NA	NA	NA
7	Constellation Energy Commodities Group	SF		NA	NA	NA
8	Coral Power	OS		NA	NA	NA
9	Coral Power	SF		NA	NA	NA
10	Cowlitz County Pub Utility Dist No 1	OS		NA	NA	NA
11	Credit Suisse Energy LLC	SF		NA	NA	NA
12	Curtiss Livestock	LU		NA	NA	NA
13	DB Energy Trading LLC	SF		NA	NA	NA
14	DR Johnson Lumber Company	LU		NA	NA	NA
	Total					

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

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

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

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

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

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

The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
59				3,400		3,400	1
					-2,597	-2,597	2
1,841				94,434		94,434	3
230,486				16,658,275		16,658,275	4
311,657				20,021,986		20,021,986	5
435				25,965		25,965	6
1,627,733				96,472,331	879,753	97,352,084	7
					17,030	17,030	8
1,130,122				61,725,243	902,235	62,627,478	9
					-138,791	-138,791	10
884,315				56,397,190	-282,296	56,114,894	11
123				6,790		6,790	12
217,234				11,322,836		11,322,836	13
66,634				3,673,304		3,673,304	14
13,186,772	9,646,444	8,978,368	121,808,550	2,308,732,360	-1,666,801,949	763,738,961	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555)
(including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Davis County Waste Management	AD		NA	NA	NA
2	Davis County Waste Management	LU		NA	NA	NA
3	Deschutes Valley Water District	LU		5.7	4.0	2.9
4	Deseret Power Electric Cooperative	LF		100	100	92
5	Deutsche Bank AG	SF		NA	NA	NA
6	Douglas County Forest Products	IU		NA	NA	NA
7	Douglas County Pub Utility Dist No 1	AD		NA	NA	NA
8	Douglas County Pub Utility Dist No 1	LU		NA	NA	NA
9	Douglas County Pub Utility Dist No 1	OS		NA	NA	NA
10	Douglas County Pub Utility Dist No 1	SF		NA	NA	NA
11	Draper Irrigation Company	IU		NA	NA	NA
12	Dry Creek	LU		NA	NA	NA
13	Dynegy Power Marketing	SF		NA	NA	NA
14	EPCOR Energy Marketing (U.S.) Inc.	SF		NA	NA	NA
	Total					

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
					73	73	1
650				28,385		28,385	2
24,746			711,148	2,483,723		3,194,871	3
747,238			13,125,162	12,504,084	3,479,670	29,108,916	4
					281,974	281,974	5
899				43,797		43,797	6
					-151,015	-151,015	7
257,836					2,572,782	2,572,782	8
68,692				1,282,880		1,282,880	9
16,410				797,685	2,971	800,656	10
33				1,779		1,779	11
8,467				405,259		405,259	12
26,085				1,782,998		1,782,998	13
52,316				2,513,972		2,513,972	14
13,186,772	9,646,444	8,978,368	121,808,550	2,308,732,360	-1,666,801,949	763,738,961	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555)
(Including power exchanges)

- 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.
- 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.
- In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Eagle Point Irrigation District	LU		0.8	0.5	0.4
2	El Paso Electric Company	SF		NA	NA	NA
3	Eugene Water & Electric Board	SF		NA	NA	NA
4	Eurus Energy America	LU		NA	NA	NA
5	Evergreen BioPower, LLC	LU		NA	NA	NA
6	Exergy Development Group, LLC	AD		NA	NA	NA
7	ExxonMobile Production Company	LU		NA	NA	NA
8	FPL Energy Power Marketing, Inc.	SF		NA	NA	NA
9	Falls Creek	LU		3.2	3.4	1.1
10	Farmers Irrigation District	LU		3.2	3.1	2.4
11	Fery, Loyd	LU		NA	NA	NA
12	Fillmore City	LF		NA	NA	NA
13	Finley BioEnergy, LLC	LU		NA	NA	NA
14	Fortis Energy Marketing & Trading GP	SF		NA	NA	NA
	Total					

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

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

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

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

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
3,314			45,365	342,796		388,161	1
38,047				2,104,070	16,786	2,120,866	2
107,973				6,264,781		6,264,781	3
117,180				4,088,418		4,088,418	4
6,536				345,975		345,975	5
					118,750	118,750	6
668,089				31,607,690		31,607,690	7
35,455				2,219,815		2,219,815	8
14,909			201,257	1,437,270		1,638,527	9
21,485			279,720	2,088,354		2,368,074	10
273				15,005		15,005	11
182				19,680		19,680	12
1,464				84,298		84,298	13
587,834				33,483,139	277,047	33,206,092	14
13,186,772	9,646,444	8,978,368	121,808,550	2,308,732,360	-1,666,801,949	763,738,961	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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**PURCHASED POWER (Account 555)
(Including power exchanges)**

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Franklin County Pub Utility Dist No. 1	SF		NA	NA	NA
2	Galesville Dam	LU		0.6	0.8	0.6
3	Garland Canal	LU		2.7	0.3	0.1
4	General Chemical Corporation			NA	NA	NA
5	George DeRuyter & Sons Dairy	IU		NA	NA	NA
6	Georgetown Irrigation Company	LU		NA	NA	NA
7	Gila River Power, L.P.	OS		NA	NA	NA
8	Gila River Power, L.P.	SF		NA	NA	NA
9	Glendale, City of	SF		NA	NA	NA
10	Grand Valley Power	LF		NA	NA	NA
11	Grant County Pub Utility Dist No 2	AD		NA	NA	NA
12	Grant County Pub Utility Dist No 2	LF		14	NA	NA
13	Grant County Pub Utility Dist No 2	LU		NA	NA	NA
14	Grant County Pub Utility Dist No 2	LU		NA	NA	NA
Total						

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
5,654				298,184		298,184	1
4,878			63,553	537,015		600,568	2
8,909			133,411	329,080		462,491	3
1,873				27,901		27,901	4
5,781				323,148		323,148	5
1,317				67,037		67,037	6
8,075				574,510		574,510	7
379,706				21,364,589		21,364,589	8
5				373		373	9
80				12,283		12,283	10
					-557,374	-557,374	11
87,600			85,193	6,405,483	333,292	6,823,968	12
741,598				12,520,954	9,204,812	21,725,766	13
931,535					9,698,148	9,698,148	14
13,186,772	9,646,444	8,978,368	121,808,550	2,308,732,360	-1,666,801,949	763,738,961	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	04/03/2008	End of 2007/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 except that "intermediate-term" means longer than one year but less than five years.

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Grant County Pub Utility Dist No 2	OS		NA	NA	NA
2	Grant County Pub Utility Dist No 2	SF		NA	NA	NA
3	Grays Harbor Public Utility District	SF		NA	NA	NA
4	Heber Light & Power Company	LF		NA	NA	NA
5	Hermiston Generating Company, L.P.	AD		NA	NA	NA
6	Hermiston Generating Company, L.P.	LU		241	241	216
7	Highland Energy LLC	SF		NA	NA	NA
8	Hill Air Force Base	AD		NA	NA	NA
9	Hill Air Force Base	LU		NA	NA	NA
10	Hurricane, City of	LF		NA	NA	NA
11	Idaho Falls, City of	AD		NA	NA	NA
12	Idaho Falls, City of	LU		NA	NA	NA
13	Idaho Falls, City of	SF		NA	NA	NA
14	Idaho Power Company	OS		NA	NA	NA
	Total					

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
					45,715	45,715	1
92,808				4,487,374	8,680	4,496,054	2
11,658				719,755		719,755	3
5,141				400,445		400,445	4
-2					226,833	226,833	5
1,702,087			34,303,979	52,944,870	459,005	87,707,854	6
3,475				218,600		218,600	7
					834	834	8
8,432				391,839		391,839	9
2,407				102,312		102,312	10
					-7,486	-7,486	11
40,101					2,646,744	2,646,744	12
5,956				329,872		329,872	13
					425	425	14
13,186,772	9,646,444	8,978,368	121,808,550	2,308,732,360	-1,666,801,949	763,738,961	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555), (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
200,227				9,513,787	490,485	10,004,272	1
2,080				104,000		104,000	2
583,940				25,976,563		25,976,563	3
593,643				32,967,728	56,262	33,023,990	4
25					1,387	1,387	5
378,000				19,915,744	-65,508	19,850,236	6
200,034				7,438,349		7,438,349	7
					10,186,670	10,186,670	8
2,146				48,396		48,396	9
1,741				91,541		91,541	10
4,852				264,933	31,042	295,975	11
11,675			254,620	1,194,550		1,449,170	12
483,125				28,075,957	-104,281	27,971,676	13
30,386				627,432	283,813	911,245	14
13,186,772	9,646,444	8,978,368	121,808,550	2,308,732,360	-1,666,801,949	763,738,961	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	04/03/2008	End of 2007/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 except that "intermediate-term" means longer than one year but less than five years.

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Los Angeles Dept. of Water & Power	SF		NA	NA	NA
2	Luckey, Paul	LU		NA	NA	NA
3	Magnesium Corporation of America	IU		NA	NA	NA
4	Magnesium Corporation of America	LF		NA	NA	NA
5	Marsh Valley Hydro & Electric Company	LU		NA	NA	NA
6	Merrill Lynch Commodities, Inc.	SF		NA	NA	NA
7	Middlefork Irrigation District	LU		NA	NA	NA
8	Mink Creek Hydro	LU		NA	NA	NA
9	Mirant Americas Energy Marketing, L.P.	SF		NA	NA	NA
10	Modesto Irrigation District	SF		NA	NA	NA
11	Monsanto	IU		NA	NA	NA
12	Morgan City	LF		NA	NA	NA
13	Morgan Stanley Capital Group, Inc.	AD		NA	NA	NA
14	Morgan Stanley Capital Group, Inc.	IF		50	50	50
	Total					

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555) (Continued)
(including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
62,506				4,138,386	61,155	4,199,541	1
289				28,954		28,954	2
214,849				10,846,413		10,846,413	3
					1,755,360	1,755,360	4
4,474				235,167		235,167	5
483,390				29,875,101	-159,711	29,715,390	6
25,215				1,381,498		1,381,498	7
8,445				426,556		426,556	8
814				25,587		25,587	9
75				3,394		3,394	10
					13,011,421	13,011,421	11
33				3,115		3,115	12
628					40,555	40,555	13
504,800			468,000	31,029,680		31,497,680	14
13,186,772	9,646,444	8,978,368	121,808,550	2,308,732,360	-1,666,801,949	763,738,961	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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**PURCHASED POWER (Account 555)
(Including power exchanges)**

- 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.
- 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.
- In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Morgan Stanley Capital Group, Inc.	SF		NA	NA	NA
2	Mountain Energy, Inc.	LU		NA	NA	NA
3	Municipal Energy Agency of Nebraska	SF		NA	NA	NA
4	Nephi City	LF		NA	NA	NA
5	Nevada Power Company	OS		NA	NA	NA
6	Nevada Power Company	SF		NA	NA	NA
7	Nicholson Sunnybar Ranch	LU		NA	NA	NA
8	North Fork Sprague	LU		0.4	0.6	0.2
9	NorthWestern Energy	SF		NA	NA	NA
10	Northern California Power Agency	SF		NA	NA	NA
11	Northpoint Energy Solutions Inc.	SF		NA	NA	NA
12	Nucor Corporation	IF		NA	NA	NA
13	O.J. Power Company	LU		NA	NA	NA
14	Occidental Power Services, Inc.	SF		NA	NA	NA
	Total					

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
5,832,562				322,772,613	314,249	323,086,862	1
17				949		949	2
4,480				203,120		203,120	3
17				1,673		1,673	4
550				25,950		25,950	5
28,836				1,003,302	922,029	1,925,331	6
1,652				85,557		85,557	7
2,256			42,575	229,238		271,813	8
563					29,609	29,609	9
33,868				1,828,630		1,828,630	10
12,006				848,488		848,488	11
					4,610,400	4,610,400	12
785				37,618		37,618	13
24,800				1,818,648		1,818,648	14
13,186,772	9,646,444	8,978,368	121,808,550	2,308,732,360	-1,666,801,949	763,738,961	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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**PURCHASED POWER (Account 555)
(Including power exchanges)**

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Odell Creek	LU		0.04	0.06	0.01
2	Oregon Environmental Industries, LLC	LU		NA	NA	NA
3	PPL EnergyPlus, LLC	SF		NA	NA	NA
4	PPL Montana, LLC	SF		NA	NA	NA
5	PPM Energy, Inc.	AD		NA	NA	NA
6	PPM Energy, Inc.	SF		NA	NA	NA
7	Pacific Gas & Electric Company	SF		NA	NA	NA
8	Pacific NW Generating Cooperative	SF		NA	NA	NA
9	Pacific Summit Energy LLC	OS		NA	NA	NA
10	Pacific Summit Energy LLC	SF		NA	NA	NA
11	Pasadena, City of	SF		NA	NA	NA
12	Payson City Corporation	LF		NA	NA	NA
13	Pinnacle West Marketing & Trading Co.	SF		NA	NA	NA
14	Platte River Power	AD		NA	NA	NA
	Total					

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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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)	
254			3,537	22,489		26,026	1
12,026				644,471		644,471	2
2,760				134,380		134,380	3
22,218				1,091,174		1,091,174	4
3					68,912	68,912	5
684,994				34,748,589	480,140	35,228,729	6
32,391				2,258,851		2,258,851	7
25,385				1,259,240		1,259,240	8
800				49,600		49,600	9
674,815				38,678,502		38,678,502	10
10,915				687,409		687,409	11
10				1,155		1,155	12
5,717				435,736		435,736	13
-5					-176	-176	14
13,186,772	9,646,444	8,978,368	121,808,550	2,308,732,360	-1,666,801,949	763,738,961	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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**PURCHASED POWER (Account 555)
(Including power exchanges)**

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

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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.

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Platte River Power	SF		NA	NA	NA
2	Portland General Electric Co.	AD		NA	NA	NA
3	Portland General Electric Co.	AD		NA	NA	NA
4	Portland General Electric Co.	LF		NA	NA	NA
5	Portland General Electric Co.	OS		NA	NA	NA
6	Portland General Electric Co.	SF		NA	NA	NA
7	Powerex	SF		NA	NA	NA
8	Preston City Hydro	LU		NA	NA	NA
9	Provo City	LF		NA	NA	NA
10	Public Service Company of Colorado	SF		NA	NA	NA
11	Public Service Company of New Mexico	OS		NA	NA	NA
12	Public Service Company of New Mexico	SF		NA	NA	NA
13	Puget Sound Energy	OS		NA	NA	NA
14	Puget Sound Energy	SF		NA	NA	NA
Total						

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
3,553					179,595	179,595	1
					118,750	118,750	2
					40,546	40,546	3
12,031					137,000	137,000	4
50				500	500	1,000	5
597,922				28,384,317	48,286	28,432,603	6
1,450,959				89,214,519		89,214,519	7
2,528				119,615		119,615	8
162				13,070		13,070	9
182,646				10,654,272		10,654,272	10
3,860				403,305	300	403,605	11
386,032				22,388,822	229,554	22,618,376	12
					20,000	20,000	13
					212,500	212,500	14
13,186,772	9,646,444	8,978,368	121,808,550	2,308,732,360	-1,666,801,949	763,738,961	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
136,860				7,015,390	43,755	7,059,145	1
51				3,001		3,001	2
320				43,200		43,200	3
34,105				1,744,060		1,744,060	4
253				25,392		25,392	5
457				25,066		25,066	6
37,005				3,025,865		3,025,865	7
10,270				239,470		239,470	8
635				14,095		14,095	9
5,588				225,137		225,137	10
151,589				8,640,578	-15,840	8,624,738	11
					3	3	12
264				14,497		14,497	13
168,940				9,148,021		9,148,021	14
13,186,772	9,646,444	8,978,368	121,808,550	2,308,732,360	-1,666,801,949	763,738,961	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Sacramento Municipal Utility District	AD		NA	NA	NA
2	Sacramento Municipal Utility District	LF		NA	NA	NA
3	Sacramento Municipal Utility District	SF		NA	NA	NA
4	Salt River Project	AD		NA	NA	NA
5	Salt River Project	OS		NA	NA	NA
6	Salt River Project	SF		NA	NA	NA
7	San Diego Gas & Electric	SF		NA	NA	NA
8	Santa Clara, City of	SF		NA	NA	NA
9	Santiam Water Control District	LU		0.2	0.2	0.1
10	Schwendiman Wind Farms Inc.	LU		NA	NA	NA
11	Seaboard Foods	OS		NA	NA	NA
12	Seattle City Light	SF		NA	NA	NA
13	Sempra Energy Solutions	SF		NA	NA	NA
14	Sempra Energy Trading LLC	AD		NA	NA	NA
	Total					

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
					64,189	64,189	1
179,757				2,568,728		2,568,728	2
23,947				1,445,815		1,445,815	3
					538	538	4
					900	900	5
276,568				15,725,151	2,114	15,727,265	6
37,364				2,316,448		2,316,448	7
6,254				357,830		357,830	8
1,566			13,632	136,029		149,661	9
					-71,234	-71,234	10
					1,495	1,495	11
168,015				8,081,705	15,009	8,096,714	12
67,968				4,247,465		4,247,465	13
					2,250	2,250	14
13,186,772	9,646,444	8,978,368	121,808,550	2,308,732,360	-1,666,801,949	763,738,961	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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**PURCHASED POWER (Account 555)
(Including power exchanges)**

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Sempra Energy Trading LLC	OS		NA	NA	NA
2	Sempra Energy Trading LLC	SF		NA	NA	NA
3	Sempra Generation	SF		NA	NA	NA
4	Sierra Pacific Power Company	AD		NA	NA	NA
5	Sierra Pacific Power Company	SF		NA	NA	NA
6	Simplot Phosphates, LLC	AD		NA	NA	NA
7	Simplot Phosphates, LLC	LU		10	13	9
8	Simplot Phosphates, LLC	OS		NA	NA	NA
9	Slate Creek	AD		NA	NA	NA
10	Slate Creek	LU		2.0	1.4	0.3
11	Snohomish Pub Utility District No. 1	SF		NA	NA	NA
12	Southern California Edison Company	OS		NA	NA	NA
13	Southern California Edison Company	SF		NA	NA	NA
14	Southwestern Public Service Company	SF		NA	NA	NA
Total						

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
1,020				47,610		47,610	1
1,696,041				110,552,414	950,899	111,503,313	2
29,478				1,858,380		1,858,380	3
6					288	288	4
37,851				1,812,007	39,431	1,851,438	5
					3,766	3,766	6
82,089			152,981	3,332,682		3,485,663	7
					28,720	28,720	8
					78,158	78,158	9
5,385			86,388	485,701		572,089	10
134,985				5,355,945		5,355,945	11
450				10,250		10,250	12
270,271				16,993,252		16,993,252	13
545				11,710		11,710	14
13,186,772	9,646,444	8,978,368	121,808,550	2,308,732,360	-1,666,801,949	763,738,961	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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**PURCHASED POWER (Account 555)
(Including power exchanges)**

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

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

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

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

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Spanish Fork City	LF		NA	NA	NA
2	Springville City	LF		NA	NA	NA
3	State of CA Dept of Water Resources	SF		NA	NA	NA
4	Strawberry Electric Service District	LF		NA	NA	NA
5	Sunnyside Cogeneration Associates	LU		48.6	50.1	48.4
6	Swiss Re Financial Prod Corporation	SF		NA	NA	NA
7	Sysco Intermountain Foods	AD		NA	NA	NA
8	Sysco Intermountain Foods	OS		NA	NA	NA
9	Tacoma, City of	SF		NA	NA	NA
10	Tesoro Refining and Marketing Company	OS		NA	NA	NA
11	Thayn Hydro LLC	LU		0.3	0.4	0.3
12	The Energy Authority	SF		NA	NA	NA
13	TransAlta Energy Marketing Inc.	AD		NA	NA	NA
14	TransAlta Energy Marketing Inc.	IF		NA	NA	NA
Total						

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
47				4,229		4,229	1
36				4,397		4,397	2
20,800				1,369,076		1,369,076	3
81				6,004		6,004	4
404,201			9,625,588	17,625,300		27,250,888	5
					93,903	93,903	6
					445	445	7
					2,135	2,135	8
25,011				1,308,398	5,806	1,314,204	9
41,543				1,892,541		1,892,541	10
2,573			38,434	141,990		180,424	11
2,562				130,061		130,061	12
					-534	-534	13
552,125				30,404,795		30,404,795	14
13,186,772	9,646,444	8,978,368	121,808,550	2,308,732,360	-1,666,801,949	763,738,961	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555)
(Including power exchanges)

- 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.
- 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.
- In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	TransAlta Energy Marketing Inc.	LF		NA	NA	NA
2	TransAlta Energy Marketing Inc.	SF		NA	NA	NA
3	Tri-State Generation & Transmission	LF		41	41	39
4	Tri-State Generation & Transmission	OS		NA	NA	NA
5	Tri-State Generation & Transmission	SF		NA	NA	NA
6	Tri-State Generation & Transmission	SF		NA	NA	NA
7	Tucson Electric Power	OS		NA	NA	NA
8	Tucson Electric Power	SF		NA	NA	NA
9	Turlock Irrigation District	SF		NA	NA	NA
10	UBS Warburg Energy LLC	IF		NA	NA	NA
11	UBS Warburg Energy LLC	SF		NA	NA	NA
12	UT Associated Municipal Power Systems	AD		NA	NA	NA
13	UT Associated Municipal Power Systems	OS		NA	NA	NA
14	UT Associated Municipal Power Systems	OS		81	81	74
Total						

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
1,667,746				53,751,270	745,235	53,006,035	1
238,580				13,987,050		13,987,050	2
228,236			8,461,050	4,575,670		13,036,720	3
15				570		570	4
					954,544	954,544	5
23,417				1,017,824	24,011	1,041,835	6
738				32,240		32,240	7
227,589				13,343,499		13,343,499	8
2,600				135,300		135,300	9
91,039				6,310,329		6,310,329	10
932,594				54,808,828		54,808,828	11
270					12,087	12,087	12
					328,985	328,985	13
452,099			3,659,976	15,949,071	1,517,894	21,526,931	14
13,186,772	9,646,444	8,978,368	121,808,550	2,308,732,360	-1,666,801,949	763,738,961	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	UT Associated Municipal Power Systems	SF		NA	NA	NA
2	Utah Municipal Power Agency	OS		NA	NA	NA
3	Utah Municipal Power Agency	SF		NA	NA	NA
4	Wadeland South LLC	AD		NA	NA	NA
5	Wadeland South LLC	LU		0.04	0.08	0.04
6	Walla Walla, City of	LU		1.9	1.6	1.5
7	Warm Springs Forest Products	LU		NA	NA	NA
8	Weber County, State of Utah	AD		NA	NA	NA
9	Weber County, State of Utah	LU		NA	NA	NA
10	Western Area Power Administration	AD		NA	NA	NA
11	Western Area Power Administration	OS		NA	NA	NA
12	Western Area Power Administration	SF		NA	NA	NA
13	Weyerhaeuser	OS		NA	NA	NA
14	Whitney, A. C.	LU		NA	NA	NA
	Total					

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
307				10,749		10,749	1
4,700				240,126		240,126	2
80				3,200		3,200	3
-40					-1,971	-1,971	4
327			40	11,472		11,512	5
12,312			135,747	1,529,086		1,664,833	6
393				8,281		8,281	7
-22					-729	-729	8
2,393				84,460		84,460	9
18					906	906	10
2,169				87,260	573,891	661,151	11
31,506				1,392,836	40,300	1,433,136	12
379,123				21,263,328		21,263,328	13
							14
13,186,772	9,646,444	8,978,368	121,808,550	2,308,732,360	-1,666,801,949	763,738,961	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4			
PURCHASED POWER (Account 555) (Including power exchanges)						
<p>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.</p> <p>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.</p> <p>3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:</p> <p>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.</p> <p>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.</p> <p>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.</p> <p>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.</p> <p>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.</p> <p>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.</p> <p>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.</p> <p>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.</p>						
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	Wolverine Creek Energy LLC	LU		NA	NA	NA
2	Yakima Tieton	LU		NA	NA	NA
3	Accrual true-up	NA		NA	NA	NA
4	Line Loss Return	AD		NA	NA	NA
5	Bookouts	AD		NA	NA	NA
6	Bookouts	AD		NA	NA	NA
7	Accrual for disputed amounts	AD		NA	NA	NA
8	Trading	AD		NA	NA	NA
9						
10	Power Exchanges					
11	Arizona Public Service Co.	EX	306	NA	NA	NA
12	Avista Corp.	EX	554	NA	NA	NA
13	Basin Electric Power Cooperative	EX	T-11	NA	NA	NA
14	Black Hills Power, Inc.	AD	246	NA	NA	NA
	Total					

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555) (Continued)
(including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
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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)	
148,933				7,979,814		7,979,814	1
6,917				372,149		372,149	2
					-27,818,841	-27,818,841	3
					3,146,781	3,146,781	4
-823					-76,136	-76,136	5
-583,940					-1,424,201,263	-1,424,201,263	6
					2,324,553	2,324,553	7
-31,579,093					-315,043,007	-315,043,007	8
							9
							10
	571,186	571,305			-530,812	-530,812	11
	1,930						12
	19,259	6,673			28,904	28,904	13
	2						14
13,186,772	9,646,444	8,978,368	121,808,550	2,308,732,360	-1,666,801,949	763,738,961	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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**PURCHASED POWER (Account 555)
(including power exchanges)**

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Black Hills Power, Inc.	EX	246	NA	NA	NA
2	Bonneville Power Administration	AD	237	NA	NA	NA
3	Bonneville Power Administration	AD	256	NA	NA	NA
4	Bonneville Power Administration	AD	347	NA	NA	NA
5	Bonneville Power Administration	EX	237	NA	NA	NA
6	Bonneville Power Administration	EX	256	NA	NA	NA
7	Bonneville Power Administration	EX	347	NA	NA	NA
8	Bonneville Power Administration	EX	368	NA	NA	NA
9	Bonneville Power Administration	EX	554	NA	NA	NA
10	Bonneville Power Administration	EX	(16)	NA	NA	NA
11	Bonneville Power Administration	EX	T-11	NA	NA	NA
12	Bonneville Power Administration	EX	T-12	NA	NA	NA
13	Chelan County Pub Utility Dist No. 1	EX	554	NA	NA	NA
14	Clark Public Utilities	AD	417	NA	NA	NA
Total						

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
	316						1
					-5,696	-5,696	2
					-24	-24	3
	-50						4
					-5,725	-5,725	5
	1,725	1,725			-13,800	-13,800	6
	1,687,802	1,697,003			-575,000	-575,000	7
	200,000	200,000					8
	139,234	28,000					9
	4,741,976	4,741,976			-22,499,508	-22,499,508	10
	4,225	2,824			62,199	62,199	11
	96,125	93,954			58,593	58,593	12
		16,875					13
	-974				226,206	226,206	14
13,186,772	9,646,444	8,978,368	121,808,550	2,308,732,360	-1,666,801,949	763,738,961	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555), (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
	530,707				28,285,778	28,285,778	1
		267,500					2
	198,156	219,584					3
	77,418	40,691			1,396,716	1,396,716	4
		14			-341	-341	5
		475			-11,868	-11,868	6
	1,355	1,688			-10,738	-10,738	7
	18,105	17,970			10,560	10,560	8
	9,095	132			454,212	454,212	9
	11,254	44,373					10
	315,721	236,965					11
	16,295	9,717			210,003	210,003	12
	157,007	155,831					13
	5,735						14
13,186,772	9,646,444	8,978,368	121,808,550	2,308,732,360	-1,666,801,949	763,738,961	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555)
(Including power exchanges)

- 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.
- 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.
- In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Public Service Company of Colorado	EX	T-12	NA	NA	NA
2	Redding, City of	EX	364	NA	NA	NA
3	Seattle City Light	EX	554	NA	NA	NA
4	Sempra Energy Solutions	EX	T-11	NA	NA	NA
5	Tri-State Generation & Transmission	AD	319	NA	NA	NA
6	Tri-State Generation & Transmission	EX	319	NA	NA	NA
7	UT Associated Municipal Power Systems	AD	T-11	NA	NA	NA
8	UT Associated Municipal Power Systems	EX	T-11	NA	NA	NA
9	Utah Municipal Power Agency	AD	T-11	NA	NA	NA
10	Utah Municipal Power Agency	EX	T-11	NA	NA	NA
11	Warm Springs Power Enterprises	AD	T-11	NA	NA	NA
12	Warm Springs Power Enterprises	EX	T-11	NA	NA	NA
13	Western Area Power Administration	AD	T-11	NA	NA	NA
14	Western Area Power Administration	EX	262	NA	NA	NA
	Total					

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
	71,753	67,965			302,753	302,753	1
	110,721	123,097			-639,237	-639,237	2
	337,571	329,409			794,863	794,863	3
	5,036	2,998			43,765	43,765	4
					6,523	6,523	5
	80,566				106,778	106,778	6
	21,737	-16,754			-730,140	-730,140	7
	115,410	63,360			1,897,216	1,897,216	8
		24,236					9
	48,954	7,892			1,986,551	1,986,551	10
					39,912	39,912	11
	1,895	7,764			-309,874	-309,874	12
	5,882	169			666,153	666,153	13
	16,764						14
13,186,772	9,646,444	8,978,368	121,808,550	2,308,732,360	-1,666,801,949	763,738,961	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555)
(Including power exchanges)

- 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.
- 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.
- In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Western Area Power Administration	EX	T-11	NA	NA	NA
2						
3	System Deviation	NA		NA	NA	NA
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
	26,551	12,957			1,606,537	1,606,537	1
							2
-3,885							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
13,186,772	9,646,444	8,978,368	121,808,550	2,308,732,360	-1,666,801,949	763,738,961	

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 326 Line No.: 2 Column: I

Green tags.

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

Settlement adjustment.

Schedule Page: 326 Line No.: 3 Column: I

Damages for non-delivery of generation.

Schedule Page: 326 Line No.: 5 Column: I

Reserve Share.

Schedule Page: 326 Line No.: 7 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326 Line No.: 11 Column: b

Arizona Public Service - Contract Termination Date: October 31, 2020.

Schedule Page: 326 Line No.: 13 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326 Line No.: 13 Column: I

Operating reserves.

Schedule Page: 326 Line No.: 14 Column: I

Reserve Share.

Schedule Page: 326.1 Line No.: 1 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.1 Line No.: 1 Column: I

Operating reserves.

Schedule Page: 326.1 Line No.: 3 Column: I

Financial Swap.

Schedule Page: 326.1 Line No.: 5 Column: I

Financial Swap.

Schedule Page: 326.1 Line No.: 6 Column: I

Financial Swap.

Schedule Page: 326.1 Line No.: 7 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.1 Line No.: 10 Column: I

Non-generation agreement.

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

Settlement adjustment.

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

Operation and maintenance expense associated with the combustion turbine located in Rapid City, South Dakota.

Schedule Page: 326.1 Line No.: 13 Column: I

Operation and maintenance expense associated with the combustion turbine located in Rapid City, South Dakota.

Schedule Page: 326.1 Line No.: 14 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.2 Line No.: 3 Column: b

Blanding - Contract Termination Date: March 31, 2012.

Schedule Page: 326.2 Line No.: 4 Column: b

Settlement adjustment.

Schedule Page: 326.2 Line No.: 4 Column: I

Settlement adjustment.

Schedule Page: 326.2 Line No.: 6 Column: b

Settlement adjustment.

Schedule Page: 326.2 Line No.: 6 Column: I

Settlement adjustment.

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 326.2 Line No.: 7 Column: b

Bonneville Power Administration - Contract Termination Date: August 31, 2011.

Schedule Page: 326.2 Line No.: 8 Column: b

Bonneville Power Administration - Contract Termination Date: 30 days written notice.

Schedule Page: 326.2 Line No.: 8 Column: l

Operating reserves.

Schedule Page: 326.2 Line No.: 9 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.2 Line No.: 9 Column: l

Operating reserves.

Schedule Page: 326.2 Line No.: 10 Column: l

Green tags.

Schedule Page: 326.2 Line No.: 11 Column: l

Reserve Share.

Schedule Page: 326.2 Line No.: 12 Column: l

Reserve Share.

Schedule Page: 326.2 Line No.: 13 Column: b

Settlement adjustment.

Schedule Page: 326.2 Line No.: 13 Column: l

Settlement adjustment.

Schedule Page: 326.3 Line No.: 2 Column: b

Settlement adjustment.

Schedule Page: 326.3 Line No.: 2 Column: l

Settlement adjustment.

Schedule Page: 326.3 Line No.: 4 Column: b

Settlement adjustment.

Schedule Page: 326.3 Line No.: 4 Column: l

Settlement adjustment.

Schedule Page: 326.3 Line No.: 7 Column: b

Settlement adjustment.

Schedule Page: 326.3 Line No.: 7 Column: l

Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.3 Line No.: 8 Column: l

Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.3 Line No.: 9 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.3 Line No.: 9 Column: l

Liability associated with paper pond at hydro facility located on the Lewis River in the state of Washington.

Schedule Page: 326.3 Line No.: 10 Column: l

Reserve Share.

Schedule Page: 326.3 Line No.: 11 Column: l

Financial Swap.

Schedule Page: 326.4 Line No.: 2 Column: b

Settlement adjustment.

Schedule Page: 326.4 Line No.: 2 Column: l

Settlement adjustment.

Schedule Page: 326.4 Line No.: 4 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.4 Line No.: 6 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.4 Line No.: 7 Column: l

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
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Financial Swap.

Schedule Page: 326.4 Line No.: 8 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.4 Line No.: 8 Column: l

Operating reserves.

Schedule Page: 326.4 Line No.: 9 Column: l

Financial Swap.

Schedule Page: 326.4 Line No.: 10 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.4 Line No.: 10 Column: l

Liability associated with paper pond at hydro facility located on the Lewis River in the state of Washington.

Schedule Page: 326.4 Line No.: 11 Column: l

Financial Swap.

Schedule Page: 326.5 Line No.: 1 Column: b

Settlement adjustment.

Schedule Page: 326.5 Line No.: 1 Column: l

Settlement adjustment.

Schedule Page: 326.5 Line No.: 4 Column: b

Deseret Generation & Transmission - Contract Termination Date: September 30, 2024.

Schedule Page: 326.5 Line No.: 4 Column: l

Operation and maintenance expense associated with a coal fired generating facility located in Vernal, Utah.

Schedule Page: 326.5 Line No.: 5 Column: l

Financial Swap.

Schedule Page: 326.5 Line No.: 7 Column: b

Settlement adjustment.

Schedule Page: 326.5 Line No.: 7 Column: l

Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.5 Line No.: 8 Column: l

Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.5 Line No.: 9 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.5 Line No.: 10 Column: l

Reserve Share.

Schedule Page: 326.6 Line No.: 2 Column: l

Line loss.

Schedule Page: 326.6 Line No.: 6 Column: b

Settlement adjustment.

Schedule Page: 326.6 Line No.: 6 Column: l

Green tags.

Schedule Page: 326.6 Line No.: 12 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.6 Line No.: 14 Column: l

Financial Swap.

Schedule Page: 326.7 Line No.: 4 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.7 Line No.: 7 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.7 Line No.: 10 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.7 Line No.: 11 Column: b

Settlement adjustment.

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
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Schedule Page: 326.7 Line No.: 11 Column: I

Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.7 Line No.: 12 Column: b

Grant County Public Utility District No. 2 - Contract Termination Date: 2 years written notice.

Schedule Page: 326.7 Line No.: 12 Column: I

Ancillary services and cost recovery adjustment.

Schedule Page: 326.7 Line No.: 13 Column: I

Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.7 Line No.: 14 Column: I

Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.8 Line No.: 1 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.8 Line No.: 1 Column: I

Operating reserves and liability associated with paper pond at hydro facility located on the Lewis River in the state of Washington.

Schedule Page: 326.8 Line No.: 2 Column: I

Reserve Share.

Schedule Page: 326.8 Line No.: 4 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.8 Line No.: 5 Column: a

Hermiston Generating Company, L.P. operates the Hermiston Plant, which is jointly owned. The respondent owns 50.0% of the plant. See page 402.3 column (c) of this Form No. 1 for further information on the Hermiston Plant.

Schedule Page: 326.8 Line No.: 5 Column: b

Settlement adjustment.

Schedule Page: 326.8 Line No.: 5 Column: I

On peak incentive, supplemental dispatch efficiency expense, start-up charges and committee settlements.

Schedule Page: 326.8 Line No.: 6 Column: a

Hermiston Generating Company, L.P. operates the Hermiston Plant, which is jointly owned. The respondent owns 50.0% of the plant. See page 402.3 column (c) of this Form No. 1 for further information on the Hermiston Plant.

Schedule Page: 326.8 Line No.: 6 Column: I

On peak incentive, supplemental dispatch efficiency expense, start-up charges and committee settlements.

Schedule Page: 326.8 Line No.: 8 Column: b

Settlement adjustment.

Schedule Page: 326.8 Line No.: 8 Column: I

Load curtailment.

Schedule Page: 326.8 Line No.: 10 Column: b

Hurricane, City of - Contract Termination Date: August 31, 2012.

Schedule Page: 326.8 Line No.: 11 Column: b

Settlement adjustment.

Schedule Page: 326.8 Line No.: 11 Column: I

Labor, equipment and administration fees associated with hydro project in Idaho Falls, Idaho.

Schedule Page: 326.8 Line No.: 12 Column: I

Labor, equipment and administration fees associated with hydro project in Idaho Falls, Idaho.

Schedule Page: 326.8 Line No.: 14 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.8 Line No.: 14 Column: I

Operating reserves.

Schedule Page: 326.9 Line No.: 1 Column: I

Reserve share and line loss.

Schedule Page: 326.9 Line No.: 4 Column: I

Financial Swap.

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
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Schedule Page: 326.9 Line No.: 5 Column: b

Settlement adjustment.

Schedule Page: 326.9 Line No.: 5 Column: l

Settlement adjustment.

Schedule Page: 326.9 Line No.: 6 Column: l

Financial Swap.

Schedule Page: 326.9 Line No.: 8 Column: l

Compensation for self-generation.

Schedule Page: 326.9 Line No.: 9 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.9 Line No.: 11 Column: l

Fixed annual payment.

Schedule Page: 326.9 Line No.: 13 Column: l

Financial Swap.

Schedule Page: 326.9 Line No.: 14 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.9 Line No.: 14 Column: l

Operating reserves.

Schedule Page: 326.10 Line No.: 1 Column: l

Line loss.

Schedule Page: 326.10 Line No.: 4 Column: b

Magnesium Corporation of America - Contract Termination Date: December 31, 2009.

Schedule Page: 326.10 Line No.: 4 Column: l

Operating reserves.

Schedule Page: 326.10 Line No.: 6 Column: l

Financial Swap.

Schedule Page: 326.10 Line No.: 11 Column: l

Compensation for interruptible service and operating reserves.

Schedule Page: 326.10 Line No.: 12 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.10 Line No.: 13 Column: b

Settlement adjustment.

Schedule Page: 326.10 Line No.: 13 Column: l

Settlement adjustment.

Schedule Page: 326.11 Line No.: 1 Column: l

Financial Swap.

Schedule Page: 326.11 Line No.: 4 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.11 Line No.: 5 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.11 Line No.: 6 Column: l

Line loss.

Schedule Page: 326.11 Line No.: 9 Column: l

Reserve Share.

Schedule Page: 326.11 Line No.: 12 Column: l

Operating reserves.

Schedule Page: 326.12 Line No.: 5 Column: b

Settlement adjustment.

Schedule Page: 326.12 Line No.: 5 Column: l

Green tags and settlement adjustment.

Schedule Page: 326.12 Line No.: 6 Column: l

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Financial Swap.

Schedule Page: 326.12 Line No.: 9 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.12 Line No.: 12 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.12 Line No.: 14 Column: b

Settlement adjustment.

Schedule Page: 326.12 Line No.: 14 Column: I

Line loss.

Schedule Page: 326.13 Line No.: 1 Column: I

Line loss.

Schedule Page: 326.13 Line No.: 2 Column: b

Settlement adjustment.

Schedule Page: 326.13 Line No.: 2 Column: I

Green tags.

Schedule Page: 326.13 Line No.: 3 Column: b

Settlement adjustment.

Schedule Page: 326.13 Line No.: 3 Column: I

Operation expense plus amortization of unrecovered costs of Cove Project.

Schedule Page: 326.13 Line No.: 4 Column: b

Portland General Electric Company - Contract Termination Date: Round Butte project no longer operating for power production purposes.

Schedule Page: 326.13 Line No.: 4 Column: I

Operation expense plus amortization of unrecovered costs of Cove Project.

Schedule Page: 326.13 Line No.: 5 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.13 Line No.: 5 Column: I

Operating reserves.

Schedule Page: 326.13 Line No.: 6 Column: I

Reserve Share.

Schedule Page: 326.13 Line No.: 9 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.13 Line No.: 11 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.13 Line No.: 11 Column: I

Operating reserves.

Schedule Page: 326.13 Line No.: 12 Column: I

Line loss.

Schedule Page: 326.13 Line No.: 13 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.13 Line No.: 13 Column: I

Liability associated with paper pond at hydro facility located on the Lewis River in the state of Washington.

Schedule Page: 326.13 Line No.: 14 Column: I

Green tags.

Schedule Page: 326.14 Line No.: 1 Column: I

Reserve Share.

Schedule Page: 326.14 Line No.: 3 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.14 Line No.: 8 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.14 Line No.: 11 Column: I

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Availability requirement shortfall.

Schedule Page: 326.14 Line No.: 12 Column: b

Settlement adjustment.

Schedule Page: 326.14 Line No.: 12 Column: l

Settlement adjustment.

Schedule Page: 326.15 Line No.: 1 Column: b

Settlement adjustment.

Schedule Page: 326.15 Line No.: 1 Column: l

Settlement adjustment.

Schedule Page: 326.15 Line No.: 2 Column: b

Sacramento Municipal Utility District - Contract Termination Date: December 31, 2014.

Schedule Page: 326.15 Line No.: 4 Column: b

Settlement adjustment.

Schedule Page: 326.15 Line No.: 4 Column: l

Line loss.

Schedule Page: 326.15 Line No.: 5 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.15 Line No.: 5 Column: l

Operating reserves.

Schedule Page: 326.15 Line No.: 6 Column: l

Line loss.

Schedule Page: 326.15 Line No.: 10 Column: l

Damages for non-delivery of generation.

Schedule Page: 326.15 Line No.: 11 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.15 Line No.: 11 Column: l

Load curtailment.

Schedule Page: 326.15 Line No.: 12 Column: l

Reserve Share.

Schedule Page: 326.15 Line No.: 14 Column: b

Settlement adjustment.

Schedule Page: 326.15 Line No.: 14 Column: l

Settlement adjustment.

Schedule Page: 326.16 Line No.: 1 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.16 Line No.: 2 Column: l

Financial Swap.

Schedule Page: 326.16 Line No.: 4 Column: b

Settlement adjustment.

Schedule Page: 326.16 Line No.: 4 Column: l

Settlement adjustment.

Schedule Page: 326.16 Line No.: 5 Column: l

Reserve share and line loss.

Schedule Page: 326.16 Line No.: 6 Column: b

Settlement adjustment.

Schedule Page: 326.16 Line No.: 6 Column: l

Load curtailment.

Schedule Page: 326.16 Line No.: 8 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.16 Line No.: 8 Column: l

Load curtailment.

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
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Schedule Page: 326.16 Line No.: 9 Column: b

Settlement adjustment.

Schedule Page: 326.16 Line No.: 9 Column: l

Settlement adjustment.

Schedule Page: 326.16 Line No.: 12 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.17 Line No.: 1 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.17 Line No.: 2 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.17 Line No.: 4 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.17 Line No.: 6 Column: l

Hedge payout.

Schedule Page: 326.17 Line No.: 7 Column: b

Settlement adjustment.

Schedule Page: 326.17 Line No.: 7 Column: l

Load curtailment.

Schedule Page: 326.17 Line No.: 8 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.17 Line No.: 8 Column: l

Load curtailment.

Schedule Page: 326.17 Line No.: 9 Column: l

Reserve Share.

Schedule Page: 326.17 Line No.: 10 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.17 Line No.: 13 Column: b

Settlement adjustment.

Schedule Page: 326.17 Line No.: 13 Column: l

Operating reserve reimbursement.

Schedule Page: 326.18 Line No.: 1 Column: b

Transalta Energy Marketing Corp. - Contract Termination Date: June 30, 2007.

Schedule Page: 326.18 Line No.: 1 Column: l

Operating reserve reimbursement.

Schedule Page: 326.18 Line No.: 3 Column: b

Tri-State Generation & Transmission - Contract Termination Date: December 31, 2020.

Schedule Page: 326.18 Line No.: 4 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.18 Line No.: 5 Column: l

Settlement on balance of energy remaining in account.

Schedule Page: 326.18 Line No.: 6 Column: l

Line loss.

Schedule Page: 326.18 Line No.: 7 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.18 Line No.: 12 Column: b

Settlement adjustment.

Schedule Page: 326.18 Line No.: 12 Column: l

Settlement adjustment and start-up and variable operation and maintenance charges.

Schedule Page: 326.18 Line No.: 13 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.18 Line No.: 13 Column: l

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Settlement on energy variation.

Schedule Page: 326.18 Line No.: 14 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.18 Line No.: 14 Column: l

Start-up and variable operation and maintenance charges.

Schedule Page: 326.19 Line No.: 2 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.19 Line No.: 4 Column: b

Settlement adjustment.

Schedule Page: 326.19 Line No.: 4 Column: l

Settlement adjustment.

Schedule Page: 326.19 Line No.: 8 Column: b

Settlement adjustment.

Schedule Page: 326.19 Line No.: 8 Column: l

Settlement adjustment.

Schedule Page: 326.19 Line No.: 10 Column: b

Settlement adjustment.

Schedule Page: 326.19 Line No.: 10 Column: l

Line loss.

Schedule Page: 326.19 Line No.: 11 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.19 Line No.: 11 Column: l

Operating reserves and settlement on energy variation.

Schedule Page: 326.19 Line No.: 12 Column: l

Reserve share and line loss.

Schedule Page: 326.19 Line No.: 13 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.20 Line No.: 3 Column: l

Represents the difference between actual purchase expenses for the period as reflected on the individual line items within this schedule, and the accruals charges to account 555 during the period and excess net power cost deferrals.

Schedule Page: 326.20 Line No.: 4 Column: l

Delivery of energy to settle loss dispute.

Schedule Page: 326.20 Line No.: 5 Column: b

Settlement adjustment.

Schedule Page: 326.20 Line No.: 5 Column: l

Recognition and reporting of gains and losses on bookouts under EITF Issue No. 03-11.

Schedule Page: 326.20 Line No.: 6 Column: l

Recognition and reporting of gains and losses on bookouts under EITF Issue No. 03-11.

Schedule Page: 326.20 Line No.: 7 Column: l

Reserve for potential liabilities associated with payable disputes.

Schedule Page: 326.20 Line No.: 8 Column: l

Recognition and reporting of gains and losses on energy trading contracts under EITF Issue No. 02-03.

Schedule Page: 326.20 Line No.: 11 Column: l

Exchange energy expense.

Schedule Page: 326.20 Line No.: 13 Column: l

Imbalance energy.

Schedule Page: 326.20 Line No.: 14 Column: b

Settlement adjustment.

Schedule Page: 326.21 Line No.: 2 Column: b

Settlement adjustment.

Schedule Page: 326.21 Line No.: 2 Column: l

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Exchange energy expense.

Schedule Page: 326.21 Line No.: 3 Column: b

Settlement adjustment.

Schedule Page: 326.21 Line No.: 3 Column: l

Load factoring and storage charges.

Schedule Page: 326.21 Line No.: 4 Column: b

Settlement adjustment.

Schedule Page: 326.21 Line No.: 5 Column: l

Exchange energy expense.

Schedule Page: 326.21 Line No.: 6 Column: l

Load factoring and storage charges.

Schedule Page: 326.21 Line No.: 7 Column: l

Exchange energy expense.

Schedule Page: 326.21 Line No.: 10 Column: h

These megawatt hours represent book entry only. No actual energy transfer took place.

Schedule Page: 326.21 Line No.: 10 Column: i

These megawatt hours represent book entry only. No actual energy transfer took place.

Schedule Page: 326.21 Line No.: 10 Column: l

Pacific Northwest Electric Power Planning and Conservation Act, FERC Electric Tariff, Original Volume No. 1.

Schedule Page: 326.21 Line No.: 11 Column: l

Imbalance energy.

Schedule Page: 326.21 Line No.: 12 Column: l

Exchange energy expense.

Schedule Page: 326.21 Line No.: 14 Column: b

Settlement adjustment.

Schedule Page: 326.21 Line No.: 14 Column: l

Exchange energy expense, load factoring and storage charges and unauthorized use.

Schedule Page: 326.22 Line No.: 1 Column: l

Exchange energy expense and unauthorized use.

Schedule Page: 326.22 Line No.: 4 Column: l

Imbalance energy.

Schedule Page: 326.22 Line No.: 5 Column: b

Settlement adjustment.

Schedule Page: 326.22 Line No.: 5 Column: l

Load factoring and storage charges.

Schedule Page: 326.22 Line No.: 6 Column: l

Load factoring and storage charges.

Schedule Page: 326.22 Line No.: 7 Column: l

Imbalance energy.

Schedule Page: 326.22 Line No.: 8 Column: l

Exchange energy expense.

Schedule Page: 326.22 Line No.: 9 Column: l

Imbalance energy.

Schedule Page: 326.22 Line No.: 12 Column: l

Imbalance energy.

Schedule Page: 326.23 Line No.: 1 Column: l

Exchange energy expense.

Schedule Page: 326.23 Line No.: 2 Column: l

Exchange energy expense.

Schedule Page: 326.23 Line No.: 3 Column: l

Exchange energy expense.

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Schedule Page: 326.23 Line No.: 4 Column: I

Imbalance energy.

Schedule Page: 326.23 Line No.: 5 Column: b

Settlement adjustment.

Schedule Page: 326.23 Line No.: 5 Column: I

Imbalance energy.

Schedule Page: 326.23 Line No.: 6 Column: I

Exchange energy expense and imbalance energy.

Schedule Page: 326.23 Line No.: 7 Column: b

Settlement adjustment.

Schedule Page: 326.23 Line No.: 7 Column: I

Imbalance energy.

Schedule Page: 326.23 Line No.: 8 Column: I

Imbalance energy.

Schedule Page: 326.23 Line No.: 9 Column: b

Settlement adjustment.

Schedule Page: 326.23 Line No.: 10 Column: I

Imbalance energy.

Schedule Page: 326.23 Line No.: 11 Column: b

Settlement adjustment.

Schedule Page: 326.23 Line No.: 11 Column: I

Imbalance energy.

Schedule Page: 326.23 Line No.: 12 Column: I

Imbalance energy.

Schedule Page: 326.23 Line No.: 13 Column: b

Settlement adjustment.

Schedule Page: 326.23 Line No.: 13 Column: I

Imbalance energy.

Schedule Page: 326.24 Line No.: 1 Column: I

Imbalance energy.

Schedule Page: 326.24 Line No.: 3 Column: b

Not applicable: adjustment for inadvertent interchange.

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(Next Page is 328)

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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as 'wheeling')					
<p>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.</p> <p>2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).</p> <p>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).</p> <p>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.</p>					
Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	
1	Basin Electric Power Cooperative	Western Area Power Admini	Powder River Energy Corp.	FNO	
2	Basin Electric Power Cooperative	Western Area Power Admini	Powder River Energy Corp.	AD	
3	Basin Electric Power Cooperative	Western Area Power Admini	Powder River Energy Corp.	FNO	
4	Basin Electric Power Cooperative	Western Area Power Admini	Powder River Energy Corp.	AD	
5	Basin Electric Power Cooperative			NF	
6	Basin Electric Power Cooperative			AD	
7	Bear Energy, LP			NF	
8	Black Hills Power & Light Company			SFP	
9	Black Hills Power & Light Company			NF	
10	Black Hills Power & Light Company			AD	
11	Black Hills Power & Light Company	PacifiCorp Merchant	Montana-Dakota Utilities	FNO	
12	Black Hills Power & Light Company	PacifiCorp Merchant	Montana-Dakota Utilities	AD	
13	Black Hills Power & Light Company	PacifiCorp Merchant	Black Hills Power & Light Com	LFP	
14	Black Hills Power & Light Company	PacifiCorp Merchant	Black Hills Power & Light Com	AD	
15	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS	
16	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD	
17	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS	
18	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD	
19	Bonneville Power Administration	Bonneville Power Administration	Umpqua Indian Utility Cooperative	FNO	
20	Bonneville Power Administration	Bonneville Power Administration	Umpqua Indian Utility Cooperative	AD	
21	Bonneville Power Administration	U.S. Bureau of Reclamation	Bonneville Power Administration	LFP	
22	Bonneville Power Administration	U.S. Bureau of Reclamation	Bonneville Power Administration	AD	
23	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS	
24	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD	
25	Bonneville Power Administration	Bonneville Power Administration	Yakama Power	FNO	
26	Bonneville Power Administration	Bonneville Power Administration	Yakama Power	AD	
27	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	FNO	
28	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD	
29	Bonneville Power Administration			AD	
30	BP Energy			AD	
31	Cargill-Alliant, LLC			NF	
32	Cargill-Alliant, LLC			AD	
33	Cargill-Alliant, LLC			SFP	
34	CitiGroup Energy Inc,			NF	
TOTAL					

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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued) (Including transactions referred to as 'wheeling')						
<p>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.</p> <p>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.</p> <p>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.</p> <p>8. Report in column (i) and (j) the total megawatthours received and delivered.</p>						
FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
7V11-3	Yellowtail Sub.	Sheridan Sub.	10	62,432	62,432	1
7V11-3	Yellowtail Sub.	Sheridan Sub.		4,491	4,491	2
7V11-3	Yellowtail Sub.	Sheridan Sub.	8	51,767	51,767	3
7V11-3	Yellowtail Sub.	Sheridan Sub.		5,206	5,206	4
7V11-8	Various	Various		20,045	20,045	5
7V11-8	Various	Various		415	415	6
7V11-8	Various	Various		8	8	7
7V11-7				72,000	72,000	8
7V11-8				3,675	3,675	9
7V11-8				14,339	14,339	10
7V11	Various	Sheridan Sub.	40	28,302	28,302	11
7V11	Various	Sheridan Sub.		98,097	98,097	12
7V11-7	Various	Wyodak Sub.	50	10,640	10,640	13
7V11-7	Various	Wyodak Sub.		166,857	166,857	14
237	Various	Various	310	1,542,691	1,542,691	15
237	Various	Various				16
324	Lost Creek Hydro	Various		263,967	263,967	17
324	Lost Creek Hydro	Various				18
7V11-3	BPA	Gazley Sub.	3	21,875	21,875	19
7V11-3	BPA	Gazley Sub.		2,209	2,209	20
7V11-7	USBR Green Spring	BPA	18	60,818	60,818	21
7V11-7	USBR Green Spring	BPA		2,148	2,148	22
368	Malin Sub.	Malin Sub.	102	686,513	686,513	23
368	Malin Sub.	Malin Sub.				24
7V11-3	BPA	White Swan/Toppeni	7	33,148	33,148	25
7V11-3	BPA	White Swan/Toppeni		3,108	3,108	26
299	Various	Various	221	1,608,200	1,608,200	27
299	Various	Various				28
7V11-7				3,777	3,777	29
7V11						30
7V11-8				665,722	665,722	31
7V11-8				4,901	4,901	32
7V11-7				168,829	168,829	33
7V11-8				1,444	1,444	34
			2,382	16,933,144	16,933,144	

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Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.

10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.

11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges (\$) (k)	Energy Charges (\$) (l)	(Other Charges) (\$) (m)	Total Revenues (\$) (k+l+m) (n)	Line No.
143,329		27,020	170,349	1
		13,404	13,404	2
162,602			162,602	3
		12,696	12,696	4
	151,276		151,276	5
		2,464	2,464	6
	47		47	7
	540,102		540,102	8
	23,512		23,512	9
	74,964	12,095	87,059	10
99,444			99,444	11
499,506		49,722	549,228	12
				13
1,113,750		34,425	1,148,175	14
3,976,610		67,947	4,044,557	15
		340,897	340,897	16
		286,253	286,253	17
		26,023	26,023	18
38,268		-4,090	34,178	19
		-217,918	-217,918	20
400,950			400,950	21
		36,450	36,450	22
		230,895	230,895	23
		19,421	19,421	24
92,590		-4,273	88,317	25
		-54,595	-54,595	26
1,041,706		1,024,573	2,066,279	27
		184,843	184,843	28
	20,430	3,276	23,706	29
		-38,250	-38,250	30
	3,829,527		3,829,527	31
		36,554	36,554	32
	1,217,058		1,217,058	33
	14,694		14,694	34
25,870,980	21,508,540	8,843,933	56,223,453	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Conoco Inc.			NF
2	Coral Power			NF
3	Cowlitz County PUD	Cowlitz County PUD	Bonneville Power Administration	OS
4	Cowlitz County PUD	Cowlitz County PUD	Bonneville Power Administration	AD
5	Deseret Generation & Transmission			SFP
6	Deseret Generation & Transmission	Deseret Generation & Transmission	Deseret Generation & Transmission	OS
7	Deseret Generation & Transmission	Deseret Generation & Transmission	Deseret Generation & Transmission	AD
8	Eugene Water & Electric Board	Eugene Water & Electric Board	Grant County PUD	LFP
9	Eugene Water & Electric Board	Eugene Water & Electric Board	Grant County PUD	AD
10	Eugene Water & Electric Board			NF
11	Eugene Water & Electric Board			SFP
12	Fall River Rural Electric Coop.	Marysville Hydro Partners	Idaho Power Company	OLF
13	Fall River Rural Electric Coop.	Marysville Hydro Partners	Idaho Power Company	AD
14	Flathead Electric Cooperative Inc.	Western Area Power Administration	Flathead Electric Coop., Inc.	FNO
15	Flathead Electric Cooperative Inc.	Western Area Power Administration	Flathead Electric Coop., Inc.	AD
16	Idaho Power Company	Nevada Power Company	Idaho Power Company	LFP
17	Idaho Power Company			SFP
18	Idaho Power Company			AD
19	Idaho Power Company			NF
20	Idaho Power Company			AD
21	Idaho Power Company			OLF
22	Idaho Power Company			AD
23	Idaho Power Company			OLF
24	Idaho Power Company			AD
25	JPM Ventures Energy			NF
26	Moon Lake Electric Association	Moon Lake Electric Association	Moon Lake Electric Association	OLF
27	Moon Lake Electric Association	Moon Lake Electric Association	Moon Lake Electric Association	AD
28	Municipal Energy Agency of Nebraska			NF
29	Morgan Stanley Capital Group, Inc.			SFP
30	Morgan Stanley Capital Group, Inc.			NF
31	Morgan Stanley Capital Group, Inc.			AD
32	Pacific Gas & Electric			OS
33	Pacific Gas & Electric			OS
34	PPM Energy Inc.			NF
	TOTAL			

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4			
TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued) (Including transactions referred to as 'wheeling')						
<p>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.</p> <p>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.</p> <p>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.</p> <p>8. Report in column (i) and (j) the total megawatthours received and delivered.</p>						
FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
7V11-8	Various			328	328	1
7V11-8	Various			703	703	2
234	Swift Unit No. 2	Woodland Sub.				3
234	Swift Unit No. 2	Woodland Sub.				4
7V11-7						5
280	Various	Various	105	1,539,792	1,539,792	6
280	Various	Various	105	146,652	146,652	7
7V11-5,7	Tieton Sub.	Various	15	52,264	52,264	8
7V11-5	Tieton Sub.	Various				9
7V11-8				3,055	3,055	10
7V11-7				14,060	14,060	11
322	Targhee Sub.	Goshen Sub.	9			12
322	Targhee Sub.	Goshen Sub.				13
7V11-3	Yellowtail Sub.	Various	1	4,381	4,381	14
7V11-3	Yellowtail Sub.	Various		518	518	15
7V11-7				24,626	24,626	16
7V11-7				281,725	281,725	17
7V11-7				3,696	3,696	18
7V11-8				318,630	318,630	19
7V11-8				8,872	8,872	20
257	Antelope Sub.	Antelope Sub.				21
257	Antelope Sub.	Antelope Sub.				22
203	Jim Bridger Sub.	Bridger Pump Station				23
203	Jim Bridger Sub.	Bridger Pump Station				24
7V11-8				11	11	25
302	Duchesne	Duchesne	3	12,715	12,715	26
302	Duchesne	Duchesne	3	1,050	1,050	27
7V11-8				1,117	1,117	28
7V11-7				200	200	29
7V11-8				66,370	66,370	30
7V11-8				53,971	53,971	31
86	Malin Sub.	Indian Springs				32
298	Sigurd-Glen Canyon	Pinto-Four Corners				33
7V11-8				261,734	261,734	34
			2,382	16,933,144	16,933,144	

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(Next Page is 330.1)

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued) (Including transactions referred to as 'wheeling')			
<p>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.</p> <p>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.</p> <p>11. Footnote entries and provide explanations following all required data.</p>			

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS				
Demand Charges (\$) (k)	Energy Charges (\$) (l)	(Other Charges) (\$) (m)	Total Revenues (\$) (k+l+m) (n)	Line No.
	2,359		2,359	1
	7,318		7,318	2
90,578			90,578	3
		8,228	8,228	4
	28,020		28,020	5
1,709,985		1,734,947	3,444,932	6
		370,018	370,018	7
334,125		37,978	372,103	8
		34,591	34,591	9
	15,840		15,840	10
	30,468		30,468	11
		138,701	138,701	12
		12,609	12,609	13
10,834		26,363	37,197	14
		3,101	3,101	15
759,375			759,375	16
	1,123,794		1,123,794	17
		16,647	16,647	18
	1,752,341		1,752,341	19
		54,732	54,732	20
		67,672	67,672	21
		6,152	6,152	22
		14,927	14,927	23
		1,357	1,357	24
	82		82	25
8,076		9,650	17,726	26
		1,644	1,644	27
	6,757		6,757	28
	4,888		4,888	29
	457,424		457,424	30
	268,547	74,634	343,181	31
		237,500	237,500	32
		369,620	369,620	33
	2,600,775		2,600,775	34
25,870,980	21,508,540	8,843,933	56,223,453	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as "wheeling")

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

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

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	PPM Energy Inc.			AD
2	PPM Energy Inc.	Stateline Wind	Stateline Wind	OS
3	PPM Energy Inc.	Stateline Wind	Stateline Wind	AD
4	PPM Energy Inc.	Uinta	Uinta	OS
5	PPM Energy Inc.	Uinta	Uinta	AD
6	PPM Energy Inc.	Exxon Mobile	Nevada/Los Angeles	LFP
7	PPM Energy Inc.	Exxon Mobile	Nevada/Los Angeles	AD
8	Portland General Electric			NF
9	Portland General Electric			AD
10	Powerex	Bonneville Power Administration	CAISO	LFP
11	Powerex	Bonneville Power Administration	CAISO	AD
12	Powerex			NF
13	Powerex			AD
14	Powerex			SFP
15	Powerex			AD
16	Powder River Energy Corporation	Var. WAPA Interconnection in PACE	S.J.R.E.A.	OLF
17	PPL Montana, LLC			NF
18	PPL Montana, LLC			AD
19	Public Service Company of Colorado			NF
20	Rainbow Energy Marketing			SFP
21	Rainbow Energy Marketing			NF
22	Rainbow Energy Marketing			AD
23	San Diego Gas & Electric			OLF
24	Seattle City & Light	PacifiCorp Merchant	Grant County PUD	LFP
25	Seawest Windpower, Inc.	Foote Creek Sub	Foote Creek Sub	OLF
26	Seawest Windpower, Inc.	Foote Creek Sub	Foote Creek Sub	AD
27	Sempra Energy Trading Co			NF
28	Sempra Energy Trading Co			AD
29	Sempra Energy Trading Co			SFP
30	Sempra Energy Solutions	Bonneville Power Administration	Oregon Direct Access	FNO
31	Sempra Energy Solutions	Bonneville Power Administration	Oregon Direct Access	AD
32	Sierra Pacific Power Company			NF
33	Sierra Pacific Power Company			AD
34	Sierra Pacific Power Company			SF
	TOTAL			

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4			
TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued) (Including transactions referred to as 'wheeling')						
<p>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.</p> <p>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.</p> <p>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.</p> <p>8. Report in column (i) and (j) the total megawatthours received and delivered.</p>						
FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
7V11-8				32,852	32,852	1
7V11-5						2
7V11-5						3
7V11-5						4
7V11-5						5
7V11-7		HarryAllen/Mona Sub.	75	324,412	324,412	6
7V11-7		HarryAllen/Mona Sub.		27,688	27,688	7
7V11-8				3,460	3,460	8
7V11-8				25	25	9
7V11-7	BPA	Weed Jct. Sub.	80	256,839	256,839	10
7V11-7	BPA	Weed Jct. Sub.		28,022	28,022	11
7V11-8				475,567	475,567	12
7V11-8				13,831	13,831	13
7V11-7				138,336	138,336	14
7V11-7				1,577	1,577	15
59	Various	Buffalo Sub.				16
7V11-8				23,695	23,695	17
7V11-8				2,976	2,976	18
7V11-8				53,695	53,695	19
7V11-7				53,362	53,362	20
7V11-8				10,252	10,252	21
7V11-8				2,056	2,056	22
86	Malin Sub.	Indian Springs				23
7V11-7	Wallula Sub.	Mid-C				24
264	Foote Creek Sub.					25
264	Foote Creek Sub.					26
7V11-8				18,257	18,257	27
7V11-8				23,090	23,090	28
7V11-7				10,753	10,753	29
7V11-3	BPA	Various	17	102,949	102,949	30
7V11-3	BPA	Various		9,094	9,094	31
7V11-8				219,861	219,861	32
7V11-8				29,492	29,492	33
7V11-7				675,819	675,819	34
			2,382	16,933,144	16,933,144	

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Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.

10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.

11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges (\$) (k)	Energy Charges (\$) (l)	(Other Charges) (\$) (m)	Total Revenues (\$) (k+l+m) (n)	Line No.
		253,200	253,200	1
		58,049	58,049	2
		-76,832	-76,832	3
		231,949	231,949	4
		26,589	26,589	5
1,670,625			1,670,625	6
		151,875	151,875	7
	28,175		28,175	8
		146	146	9
1,447,875			1,447,875	10
		131,625	131,625	11
	3,272,638		3,272,638	12
		85,997	85,997	13
	852,844		852,844	14
		4,742	4,742	15
		175	175	16
	143,122		143,122	17
		17,386	17,386	18
	459,684		459,684	19
	254,823		254,823	20
	63,052		63,052	21
		11,166	11,166	22
		33,249	33,249	23
212,625			212,625	24
		42,871	42,871	25
		3,897	3,897	26
	89,056		89,056	27
		122,828	122,828	28
	74,574		74,574	29
127,932		17,608	145,540	30
		11,273	11,273	31
	1,015,403		1,015,403	32
		133,402	133,402	33
	2,421,645		2,421,645	34
25,870,980	21,508,540	8,843,933	56,223,453	

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as 'wheeling')					
<p>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.</p> <p>2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).</p> <p>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).</p> <p>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.</p>					
Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	
1	Sierra Pacific Power Company			AD	
2	Southern California Edison Company			OS	
3	Southern California Edison Company			OS	
4	State of South Dakota	Western Area Power Administration	Black Hills Power & Light Company	LFP	
5	State of South Dakota	Western Area Power Administration	Black Hills Power & Light Company	AD	
6	TransAlta Energy			NF	
7	TransAlta Energy			AD	
8	Tri-State Generation & Transmission			OS	
9	Tri-State Generation & Transmission			AD	
10	Tri-State Generation & Transmission			NF	
11	Tri-State Generation & Transmission			AD	
12	United States Bureau of Reclamation	Bonneville Power Administration	U.S. Bureau of Reclamation	OLF	
13	United States Bureau of Reclamation	Bonneville Power Administration	U.S. Bureau of Reclamation	AD	
14	United States Bureau of Reclamation	Bonneville Power Administration	Crooked River Irrigation District	OLF	
15	United States Bureau of Reclamation	Bonneville Power Administration	U.S. Bureau of Reclamation	OLF	
16	Utah Associated Municipal Power	Utah Associated Municipal Power	Utah Associated Municipal Power	OS	
17	Utah Associated Municipal Power	Utah Associated Municipal Power	Utah Associated Municipal Power	AD	
18	Utah Municipal Power Agency	Utah Municipal Power Agency	Utah Municipal Power Agency	OS	
19	Utah Municipal Power Agency	Utah Municipal Power Agency	Utah Municipal Power Agency	AD	
20	Warm Springs Power Enterprises	Warm Springs Enterprises	Portland General Electric Co.	OLF	
21	Warm Springs Power Enterprises	Warm Springs Enterprises	Portland General Electric Co.	AD	
22	Western Area Power Administration	Western Area Power Administration	Various WAPA Customers in PACE	OS	
23	Western Area Power Administration	Western Area Power Administration	Various WAPA Customers in PACE	AD	
24	Western Area Power Administration	Western Area Power Administration	Various WAPA Customers in PACE	NF	
25	Western Area Power Administration	Western Area Power Administration	Various WAPA Customers in PACE	AD	
26	Western Area Power Administration	Western Area Power Administration	Western Area Power Administration	FNO	
27	Western Area Power Administration	Western Area Power Administration	Western Area Power Administration	AD	
28	Weyerhaeuser Company	Weyerhaeuser Company	Bonneville Power Administration	AD	
29					
30	Accrual true-up				
31					
32					
33					
34					
	TOTAL				

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4			
TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued) (Including transactions referred to as 'wheeling')						
<p>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.</p> <p>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.</p> <p>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.</p> <p>8. Report in column (i) and (j) the total megawatthours received and delivered.</p>						
FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
7V11-7				12,400	12,400	1
86	Malin Sub.	Indian Springs				2
298						3
7V11-7	Yellowtail Sub.	Wyodak Sub.	4	16,760	16,760	4
7V11-7	Yellowtail Sub.	Wyodak Sub.		1,517	1,517	5
7V11-8				100	100	6
7V11-8						7
123	Various	Various	31	151,795	151,795	8
123				15,553	15,553	9
7V11-8				35,548	35,548	10
7V11-8				550	550	11
35	Franklin Sub.	Burbank Pumps		29,410	29,410	12
35	Franklin Sub.	Burbank Pumps		772	772	13
67	Redmond Sub.	Crooked River Pump		11,298	11,298	14
67	Pasco Sub.	Dodd Road Sub.				15
297	Various	Various	338	2,991,342	2,991,342	16
297	Various	Various		278,500	278,500	17
279	Various	Various	109	557,139	557,139	18
279	Various	Various		46,827	46,827	19
591	Pelton Reregulation	Round Butte Sub.	16	76,149	76,149	20
591	Pelton Reregulation	Round Butte Sub.		8,219	8,219	21
262,263	Various	Various	328	1,548,722	1,548,722	22
262,263	Various	Various	328	149,486	149,486	23
7V11-8	Various	Various		27,424	27,424	24
7V11-8	Various	Various		2,909	2,909	25
7V11	Wyoming Distribution	Wyoming Distribution	1	6,350	6,350	26
7V11	Wyoming Distribution			3	3	27
320, 7V11-3	Western Kraft Sub.	Alvey Sub.	45	22,317	22,317	28
						29
						30
						31
						32
						33
						34
			2,382	16,933,144	16,933,144	

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Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4	
TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued) (including transactions referred to as 'wheeling')				
<p>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.</p> <p>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.</p> <p>11. Footnote entries and provide explanations following all required data.</p>				
REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS				
Demand Charges (\$) (k)	Energy Charges (\$) (l)	(Other Charges) (\$) (m)	Total Revenues (\$) (k+l+m) (n)	Line No.
		51,150	51,150	1
		204,248	204,248	2
		369,620	369,620	3
89,100			89,100	4
		8,100	8,100	5
	584		584	6
		99	99	7
91,107			91,107	8
		1,145	1,145	9
	256,749		256,749	10
		13,432	13,432	11
29,410			29,410	12
		772	772	13
9,915	911	581	11,407	14
		2,669	2,669	15
6,875,087		299,727	7,174,814	16
		1,061,852	1,061,852	17
2,112,594		98,895	2,210,989	18
		194,599	194,599	19
109,725			109,725	20
		9,975	9,975	21
2,593,313		1,000	2,594,313	22
		230,780	230,780	23
	405,057		405,057	24
		60,035	60,035	25
19,944		-3,012	16,932	26
		-31,111	-31,111	27
		-382,646	-382,646	28
				29
		80,425	80,425	30
				31
				32
				33
				34
25,870,980	21,508,540	8,843,933	56,223,453	

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 328 Line No.: 1 Column: d

Evergreen Network Transmission Service under the Open Access Transmission Tariff (S.A. 228 & 233) terminating with 12-month notification.

Schedule Page: 328 Line No.: 1 Column: m

Regulation & Frequency Response. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328 Line No.: 2 Column: d

Evergreen Network Transmission Service under the Open Access Transmission Tariff (S.A. 228 & 233) terminating with 12-month notification.

Schedule Page: 328 Line No.: 2 Column: m

Regulation & Frequency Response. December 2006 Service.

Schedule Page: 328 Line No.: 3 Column: d

Evergreen Network Transmission Service under the Open Access Transmission Tariff (S.A. 228 & 233) terminating with 12-month notification.

Schedule Page: 328 Line No.: 4 Column: d

Evergreen Network Transmission Service under the Open Access Transmission Tariff (S.A. 228 & 233) terminating with 12-month notification.

Schedule Page: 328 Line No.: 4 Column: m

December 2006 Service.

Schedule Page: 328 Line No.: 5 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 5 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 5 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 6 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 6 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 6 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 6 Column: m

December 2006 Service.

Schedule Page: 328 Line No.: 7 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 7 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 7 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 8 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 8 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 8 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 9 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 9 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 9 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 10 Column: b

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PacifiCorp		04/03/2008	2007/Q4
FOOTNOTE DATA			

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 10 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 10 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 10 Column: m

December 2006 Service.

Schedule Page: 328 Line No.: 11 Column: d

Network Transmission Service under the Open Access Transmission Tariff (S.A. 347) terminating on December 31, 2017.

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

Network Transmission Service under the Open Access Transmission Tariff (S.A. 347) terminating on December 31, 2017.

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

December 2006 Service.

Schedule Page: 328 Line No.: 13 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 67) terminating on December 31, 2023.

Schedule Page: 328 Line No.: 14 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 67) terminating on December 31, 2023.

Schedule Page: 328 Line No.: 14 Column: m

December 2006 Service.

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

General Transfer Agreement for network service in PACW. Evergreen.

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

Demand dollars plus a fixed cost calculated using plant investment values at various U.S. government facilities.

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

General Transfer Agreement for network service in PACW. Evergreen.

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

Demand dollars plus a fixed cost calculated using plant investment values at various U.S. government facilities. December 2006 Service.

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

Network Transmission Service terminating on October 31, 2008.

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

Demand dollars plus a fixed cost calculated using plant investment values at various U.S. government facilities.

Schedule Page: 328 Line No.: 18 Column: d

Network Transmission Service terminating on October 31, 2008.

Schedule Page: 328 Line No.: 18 Column: m

Demand dollars plus a fixed cost calculated using plant investment values at various U.S. government facilities. December 2006 Service.

Schedule Page: 328 Line No.: 19 Column: d

Network Transmission Service and Distribution Delivery Service under the Open Access Transmission Tariff (S.A. 229) terminating on September 30, 2011.

Schedule Page: 328 Line No.: 19 Column: f

Bonneville Power Administration.

Schedule Page: 328 Line No.: 19 Column: m

Distribution Service Charge. Primary Delivery Service. Regulation & Frequency Response. Primary Delivery & Distribution Services REFUND.

Schedule Page: 328 Line No.: 20 Column: d

Network Transmission Service and Distribution Delivery Service under the Open Access Transmission Tariff (S.A. 229) terminating on September 30, 2011.

Schedule Page: 328 Line No.: 20 Column: f

Bonneville Power Administration.

Schedule Page: 328 Line No.: 20 Column: m

Distribution Service Charge. Primary Delivery Service. Regulation & Frequency Response. December 2006 Service. Primary Delivery

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FOOTNOTE DATA			

& Distribution Services REFUND.

Schedule Page: 328 Line No.: 21 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 179) terminating on September 30, 2025.

Schedule Page: 328 Line No.: 21 Column: g

Bonneville Power Administration.

Schedule Page: 328 Line No.: 22 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 179) terminating on September 30, 2025.

Schedule Page: 328 Line No.: 22 Column: g

Bonneville Power Administration.

Schedule Page: 328 Line No.: 22 Column: m

December 2006 Service.

Schedule Page: 328 Line No.: 23 Column: d

Use of Facilities Agreement for the Malin Transformer under the AC Intertie Agreement with BPA dated June 1, 1994. Subject to termination upon mutual agreement.

Schedule Page: 328 Line No.: 23 Column: m

Sole use of facilities charge.

Schedule Page: 328 Line No.: 24 Column: d

Use of Facilities Agreement for the Malin Transformer under the AC Intertie Agreement with BPA dated June 1, 1994. Subject to termination upon mutual agreement.

Schedule Page: 328 Line No.: 24 Column: m

Sole use of facilities charge. December 2006 Service.

Schedule Page: 328 Line No.: 25 Column: d

Network Transmission Service and Distribution Delivery Service under the Open Access Transmission Tariff (S.A. 328) terminating on September 30, 2008.

Schedule Page: 328 Line No.: 25 Column: f

Bonneville Power Administration.

Schedule Page: 328 Line No.: 25 Column: m

Distribution Service Charge. Primary Delivery Service. Regulation & Frequency Response. Deposit Refund. Primary Delivery & Distribution Services REFUND. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328 Line No.: 26 Column: d

Network Transmission Service and Distribution Delivery Service under the Open Access Transmission Tariff (S.A. 328) terminating on September 30, 2008.

Schedule Page: 328 Line No.: 26 Column: f

Bonneville Power Administration.

Schedule Page: 328 Line No.: 26 Column: m

Distribution Service Charge. Primary Delivery Service. Regulation & Frequency Response. December 2006 Service. Primary Delivery & Distribution Services REFUND.

Schedule Page: 328 Line No.: 27 Column: d

General Transfer Agreement for network service in PACE. Evergreen.

Schedule Page: 328 Line No.: 27 Column: m

Sole use of facilities charge. Charges for monitoring, scheduling, load following and spinning reserve.

Schedule Page: 328 Line No.: 28 Column: d

General Transfer Agreement for network service in PACE. Evergreen.

Schedule Page: 328 Line No.: 28 Column: m

Sole use of facilities charge. Charges for monitoring, scheduling, load following and spinning reserve. December 2006 Service.

Schedule Page: 328 Line No.: 29 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 29 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 29 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 29 Column: m

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FOOTNOTE DATA			

December 2006 Service.

Schedule Page: 328 Line No.: 30 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 30 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 30 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 30 Column: m

Primary Delivery & Distribution Services REFUND.

Schedule Page: 328 Line No.: 31 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 31 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 31 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 32 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 32 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 32 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 32 Column: m

December 2006 Service.

Schedule Page: 328 Line No.: 33 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 33 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 33 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 34 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 34 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 34 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 1 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 1 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 1 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 2 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 2 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 2 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 3 Column: d

Agreement providing for transmission and operation of Cowlitz' Swift 2 Hydro Generation. Payment is for 26% of annual costs of Swift-Cowlitz Transmission Line. Agreement is for the life of Swift Unit No. 2.

Schedule Page: 328.1 Line No.: 4 Column: d

Agreement providing for transmission and operation of Cowlitz' Swift 2 Hydro Generation. Payment is for 26% of annual costs of

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FOOTNOTE DATA			

Swift-Cowlitz Transmission Line. Agreement is for the life of Swift Unit No. 2.

Schedule Page: 328.1 Line No.: 4 Column: m

December 2006 Service.

Schedule Page: 328.1 Line No.: 5 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 5 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 5 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 6 Column: d

Transmission Service and Operating Agreement for network service in PACE. Subject to termination upon mutual agreement.

Schedule Page: 328.1 Line No.: 6 Column: m

Charges for monitoring, scheduling, load following and spinning reserve. Distribution Service Charge. Primary Delivery Service. Meter Interrogation Services.

Schedule Page: 328.1 Line No.: 7 Column: d

Transmission Service and Operating Agreement for network service in PACE. Subject to termination upon mutual agreement.

Schedule Page: 328.1 Line No.: 7 Column: m

Charges for monitoring, scheduling, load following and spinning reserve. Distribution Service Charge. Primary Delivery Service. Meter Interrogation Services. December 2006 Service.

Schedule Page: 328.1 Line No.: 8 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff, (S.A. 332) terminating July 1, 2008.

Schedule Page: 328.1 Line No.: 8 Column: m

Charges for monitoring, scheduling, load following and spinning reserve. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.1 Line No.: 9 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff, (S.A. 332) terminating July 1, 2008.

Schedule Page: 328.1 Line No.: 9 Column: m

Charges for monitoring, scheduling, load following and spinning reserve. December 2006 Service.

Schedule Page: 328.1 Line No.: 10 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 10 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 10 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 11 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 11 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 11 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 12 Column: d

Point-to-Point Transmission Service terminating on July 31, 2028.

Schedule Page: 328.1 Line No.: 12 Column: m

Sole use of facilities charge.

Schedule Page: 328.1 Line No.: 13 Column: d

Point-to-Point Transmission Service terminating on July 31, 2028.

Schedule Page: 328.1 Line No.: 13 Column: m

Sole use of facilities charge. December 2006 Service.

Schedule Page: 328.1 Line No.: 14 Column: d

Evergreen Network Transmission Service and Distribution Delivery Service under the Open Access Transmission Tariff (S.A. 227).

Schedule Page: 328.1 Line No.: 14 Column: m

Distribution Service Charge. Primary Delivery Service. Regulation & Frequency Response.

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FOOTNOTE DATA			

Schedule Page: 328.1 Line No.: 15 Column: d

Evergreen Network Transmission Service and Distribution Delivery Service under the Open Access Transmission Tariff (S.A. 227).

Schedule Page: 328.1 Line No.: 15 Column: m

December 2006 Service.

Schedule Page: 328.1 Line No.: 16 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 212) terminating May 31, 2009.

Schedule Page: 328.1 Line No.: 17 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 17 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 17 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 18 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 18 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 18 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 18 Column: m

December 2006 Service.

Schedule Page: 328.1 Line No.: 19 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 19 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 19 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 20 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 20 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 20 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 20 Column: m

December 2006 Service.

Schedule Page: 328.1 Line No.: 21 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.1 Line No.: 21 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.1 Line No.: 21 Column: d

Use of Facilities Agreement - Antelope Substation (S.A. 257) terminating codeterminous with the Idaho/USDOE Supply Agreement.

Schedule Page: 328.1 Line No.: 21 Column: m

Sole use of facilities charge.

Schedule Page: 328.1 Line No.: 22 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.1 Line No.: 22 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.1 Line No.: 22 Column: d

Use of Facilities Agreement - Antelope Substation (S.A. 257) terminating codeterminous with the Idaho/USDOE Supply Agreement.

Schedule Page: 328.1 Line No.: 22 Column: m

December 2006 Service.

Schedule Page: 328.1 Line No.: 23 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

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Schedule Page: 328.1 Line No.: 23 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.1 Line No.: 23 Column: d

Use of Facilities Agreement - Jim Bridger Pump (S.A. 203) - termination upon 12-month written notice.

Schedule Page: 328.1 Line No.: 23 Column: m

Sole use of facilities charge.

Schedule Page: 328.1 Line No.: 24 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.1 Line No.: 24 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.1 Line No.: 24 Column: d

Use of Facilities Agreement - Jim Bridger Pump (S.A. 203) - termination upon 12-month written notice.

Schedule Page: 328.1 Line No.: 24 Column: m

December 2006 Service.

Schedule Page: 328.1 Line No.: 25 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 25 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 25 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 26 Column: d

Transmission Service and Interconnection Agreement for network service in PACE. Terminates in 2047

Schedule Page: 328.1 Line No.: 26 Column: m

Sole use of facilities charge.

Schedule Page: 328.1 Line No.: 27 Column: d

Transmission Service and Interconnection Agreement for network service in PACE. Terminates in 2047

Schedule Page: 328.1 Line No.: 27 Column: m

December 2006 Service.

Schedule Page: 328.1 Line No.: 28 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 28 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 28 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 29 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 29 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 29 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 30 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 30 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 30 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 31 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 31 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 31 Column: d

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Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 31 Column: m

December 2006 Service.

Schedule Page: 328.1 Line No.: 32 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.1 Line No.: 32 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.1 Line No.: 32 Column: d

Malin to Indian Springs use of facilities Terminating August 1, 2007. FERC ruled on July 30, 2007, to extend the agreement through December 2007.

Schedule Page: 328.1 Line No.: 32 Column: m

Sole use of facilities charge.

Schedule Page: 328.1 Line No.: 33 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.1 Line No.: 33 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.1 Line No.: 33 Column: d

Use of Facilities Agreement - Phase Shifting Transformers At Sigurd-Glen Canyon 230kv transmission line and Pinto-Four Corners 345kv transmission line (S.A. 298), terminating February 12, 2020.

Schedule Page: 328.1 Line No.: 33 Column: m

Demand dollars plus a fixed cost calculated using plant investment values at various U.S. government facilities.

Schedule Page: 328.1 Line No.: 34 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 34 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 34 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 1 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 1 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 1 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 1 Column: m

December 2006 Service.

Schedule Page: 328.2 Line No.: 2 Column: d

Ancillary Services under the Open Access Transmission Tariff (S.A. 313) in effect until superceded.

Schedule Page: 328.2 Line No.: 2 Column: m

Charges for monitoring, scheduling, load following and spinning reserve. Unauthorized Use of Transmission Service and refunds.

Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.2 Line No.: 3 Column: d

Ancillary Services under the Open Access Transmission Tariff (S.A. 313) in effect until superceded.

Schedule Page: 328.2 Line No.: 3 Column: m

Charges for monitoring, scheduling, load following and spinning reserve. Settlement adjustment. Unauthorized Use of Transmission Service and refunds. December 2006 Service.

Schedule Page: 328.2 Line No.: 4 Column: d

Ancillary Services under the Open Access Transmission Tariff (S.A. 315) in effect until superceded.

Schedule Page: 328.2 Line No.: 4 Column: m

Charges for monitoring, scheduling, load following and spinning reserve. Regulation & Frequency Response. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.2 Line No.: 5 Column: d

Ancillary Services under the Open Access Transmission Tariff (S.A. 315) in effect until superceded.

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Schedule Page: 328.2	Line No.: 5	Column: m
December 2006 Service.		
Schedule Page: 328.2	Line No.: 6	Column: d
Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 279). Terminates April 30, 2008		
Schedule Page: 328.2	Line No.: 6	Column: f
Exxon Metering Station.		
Schedule Page: 328.2	Line No.: 7	Column: d
Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 279). Terminates April 30, 2008		
Schedule Page: 328.2	Line No.: 7	Column: f
Exxon Metering Station.		
Schedule Page: 328.2	Line No.: 7	Column: m
December 2006 Service.		
Schedule Page: 328.2	Line No.: 8	Column: b
Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.		
Schedule Page: 328.2	Line No.: 8	Column: c
Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.		
Schedule Page: 328.2	Line No.: 8	Column: d
Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.		
Schedule Page: 328.2	Line No.: 9	Column: b
Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.		
Schedule Page: 328.2	Line No.: 9	Column: c
Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.		
Schedule Page: 328.2	Line No.: 9	Column: d
Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.		
Schedule Page: 328.2	Line No.: 9	Column: m
December 2006 Service.		
Schedule Page: 328.2	Line No.: 10	Column: d
Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 169) terminating on September 30, 2012. Customer assigned 15 mw to PacifiCorp Merchant through June 30, 2008.		
Schedule Page: 328.2	Line No.: 10	Column: f
Bonneville Power Administration.		
Schedule Page: 328.2	Line No.: 11	Column: d
Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 169) terminating on September 30, 2012. Customer assigned 15 mw to PacifiCorp Merchant through June 30, 2008.		
Schedule Page: 328.2	Line No.: 11	Column: f
Bonneville Power Administration.		
Schedule Page: 328.2	Line No.: 11	Column: m
December 2006 Service.		
Schedule Page: 328.2	Line No.: 12	Column: b
Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.		
Schedule Page: 328.2	Line No.: 12	Column: c
Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.		
Schedule Page: 328.2	Line No.: 12	Column: d
Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.		
Schedule Page: 328.2	Line No.: 13	Column: b
Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.		
Schedule Page: 328.2	Line No.: 13	Column: c
Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.		
Schedule Page: 328.2	Line No.: 13	Column: d
Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.		
Schedule Page: 328.2	Line No.: 13	Column: m
December 2006 Service.		

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Schedule Page: 328.2 Line No.: 14 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 14 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 14 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 15 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 15 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 15 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 15 Column: m

December 2006 Service.

Schedule Page: 328.2 Line No.: 16 Column: c

S.J.R.E.A. is the Sheridan Johnson Rural Electrification Association.

Schedule Page: 328.2 Line No.: 16 Column: d

Agreement providing for transmission service from Western Area Power Administration's Casper Substation in Wyoming and Yellowtail Substation in Montana to Sheridan-Johnson's load at PacifiCorp's Buffalo Substation in Wyoming.

Schedule Page: 328.2 Line No.: 16 Column: m

Sole use of facilities charge.

Schedule Page: 328.2 Line No.: 17 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 17 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 17 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 18 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 18 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 18 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 18 Column: m

December 2006 Service.

Schedule Page: 328.2 Line No.: 19 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 19 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 19 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 20 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 21 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 21 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 21 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 22 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 22 Column: c

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Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 22 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 22 Column: m

December 2006 Service.

Schedule Page: 328.2 Line No.: 23 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 23 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 23 Column: d

Malin to Indian Springs use of facilities Terminating August 1, 2007. FERC ruled on July 30, 2007, to extend the agreement through December 2007.

Schedule Page: 328.2 Line No.: 23 Column: m

Sole use of facilities charge.

Schedule Page: 328.2 Line No.: 24 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff, (S.A. 289) terminating November 30, 2008.

Schedule Page: 328.2 Line No.: 25 Column: d

Use of Facilities (S.A. 264) terminating July 2014.

Schedule Page: 328.2 Line No.: 25 Column: m

Sole use of facilities charge.

Schedule Page: 328.2 Line No.: 26 Column: d

Use of Facilities (S.A. 264) terminating July 2014.

Schedule Page: 328.2 Line No.: 26 Column: m

December 2006 Service.

Schedule Page: 328.2 Line No.: 27 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 27 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 27 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 28 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 28 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 28 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 28 Column: m

December 2006 Service.

Schedule Page: 328.2 Line No.: 29 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 29 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 29 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 30 Column: d

Network Transmission Service under the Open Access Transmission Tariff (S.A. 299). Service provided pursuant to rules & regulations of Oregon Direct Access. Termination upon notification pursuant to Oregon Direct Access and Open Access Transmission Tariff.

Schedule Page: 328.2 Line No.: 30 Column: f

Bonneville Power Administration.

Schedule Page: 328.2 Line No.: 30 Column: m

Regulation & Frequency Response. Penalty revenues covering imbalance charges per Schedules 4 and 9.

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Schedule Page: 328.2 Line No.: 31 Column: d

Network Transmission Service under the Open Access Transmission Tariff (S.A. 299). Service provided pursuant to rules & regulations of Oregon Direct Access. Termination upon notification pursuant to Oregon Direct Access and Open Access Transmission Tariff.

Schedule Page: 328.2 Line No.: 31 Column: f

Bonneville Power Administration.

Schedule Page: 328.2 Line No.: 31 Column: m

Regulation & Frequency Response. December 2006 Service.

Schedule Page: 328.2 Line No.: 32 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 32 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 32 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 33 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 33 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 33 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 33 Column: m

December 2006 Service.

Schedule Page: 328.2 Line No.: 34 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 34 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 34 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 1 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 1 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 1 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 1 Column: m

December 2006 Service.

Schedule Page: 328.3 Line No.: 2 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 2 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 2 Column: d

Malin to Indian Springs use of facilities Terminating August 1, 2007. FERC ruled on July 30, 2007, to extend the agreement through December 2007.

Schedule Page: 328.3 Line No.: 2 Column: m

Sole use of facilities charge.

Schedule Page: 328.3 Line No.: 3 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 3 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 3 Column: d

Use of Facilities Agreement - Phase Shifting Transformers At Sigurd-Glen Canyon 230kv transmission line and Pinto-Four Corners 345kv transmission line (S.A. 298), terminating February 12, 2020.

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Schedule Page: 328.3 Line No.: 3 Column: f

Sigurd-Glen Canyon.

Schedule Page: 328.3 Line No.: 3 Column: g

Pinto-Four Corners.

Schedule Page: 328.3 Line No.: 3 Column: m

Demand dollars plus a fixed cost calculated using plant investment values at various U.S. government facilities.

Schedule Page: 328.3 Line No.: 4 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 170) terminating on May 31, 2008.

Schedule Page: 328.3 Line No.: 5 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 170) terminating on May 31, 2008.

Schedule Page: 328.3 Line No.: 5 Column: m

December 2006 Service.

Schedule Page: 328.3 Line No.: 6 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 6 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 6 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 7 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 7 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 7 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 7 Column: m

December 2006 Service.

Schedule Page: 328.3 Line No.: 8 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 8 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 8 Column: d

Transmission Service Agreement (S.A. 123) for Network Services in PACE Terminating upon written notification.

Schedule Page: 328.3 Line No.: 9 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 9 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 9 Column: d

Transmission Service Agreement (S.A. 123) for Network Services in PACE Terminating upon written notification.

Schedule Page: 328.3 Line No.: 9 Column: m

December 2006 Service.

Schedule Page: 328.3 Line No.: 10 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 10 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 10 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 11 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 11 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 11 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

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Schedule Page: 328.3 Line No.: 11 Column: m

December 2006 Service.

Schedule Page: 328.3 Line No.: 12 Column: d

March 26, 1957 Columbia Basin Project (Burbank Pump) wheeling agreement, letter agreement extended to September 30, 2008.

Schedule Page: 328.3 Line No.: 13 Column: d

March 26, 1957 Columbia Basin Project (Burbank Pump) wheeling agreement, letter agreement extended to September 30, 2008.

Schedule Page: 328.3 Line No.: 13 Column: m

December 2006 Service.

Schedule Page: 328.3 Line No.: 14 Column: d

October 9, 1962 Crooked River Project wheeling agreement.

Schedule Page: 328.3 Line No.: 14 Column: m

Demand dollars plus a fixed cost calculated using plant investment values at various U.S. government facilities.

Schedule Page: 328.3 Line No.: 15 Column: d

March 26, 1957 Columbia Basin Project (Burbank Pump) wheeling agreement, letter agreement extended to September 30, 2008.

Schedule Page: 328.3 Line No.: 15 Column: m

Sole use of facilities charge.

Schedule Page: 328.3 Line No.: 16 Column: d

Transmission Service and Operating Agreement for network service in PACE. Subject to termination upon mutual agreement.

Schedule Page: 328.3 Line No.: 16 Column: m

Charges for monitoring, scheduling, load following and spinning reserve. Distribution Service Charge.

Schedule Page: 328.3 Line No.: 17 Column: d

Transmission Service and Operating Agreement for network service in PACE. Subject to termination upon mutual agreement.

Schedule Page: 328.3 Line No.: 17 Column: m

Charges for monitoring, scheduling, load following and spinning reserve. Settlement adjustment. Distribution Service Charge.

December 2006 Service.

Schedule Page: 328.3 Line No.: 18 Column: d

Transmission Service and Operating Agreement for network service in PACE. Subject to termination upon mutual agreement.

Schedule Page: 328.3 Line No.: 18 Column: m

Charges for monitoring, scheduling, load following and spinning reserve.

Schedule Page: 328.3 Line No.: 19 Column: d

Transmission Service and Operating Agreement for network service in PACE. Subject to termination upon mutual agreement.

Schedule Page: 328.3 Line No.: 19 Column: m

Charges for monitoring, scheduling, load following and spinning reserve. December 2006 Service.

Schedule Page: 328.3 Line No.: 20 Column: d

Transmission Service Agreement (R.S. 591) terminating January 1, 2032

Schedule Page: 328.3 Line No.: 21 Column: d

Transmission Service Agreement (R.S. 591) terminating January 1, 2032

Schedule Page: 328.3 Line No.: 21 Column: m

December 2006 Service.

Schedule Page: 328.3 Line No.: 22 Column: d

March 26, 1957 Columbia Basin Project (Burbank Pump) wheeling agreement, letter agreement extended to September 30, 2008.

Schedule Page: 328.3 Line No.: 22 Column: m

Demand dollars plus a fixed cost calculated using plant investment values at various U.S. government facilities.

Schedule Page: 328.3 Line No.: 23 Column: d

March 26, 1957 Columbia Basin Project (Burbank Pump) wheeling agreement, letter agreement extended to September 30, 2008.

Schedule Page: 328.3 Line No.: 23 Column: m

December 2006 Service.

Schedule Page: 328.3 Line No.: 24 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 25 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 25 Column: m

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

December 2006 Service.

Schedule Page: 328.3 Line No.: 26 Column: d

Evergreen Network Transmission Service under the Open Access Transmission Tariff (S.A. 175).

Schedule Page: 328.3 Line No.: 26 Column: m

Distribution Service Charge. Primary Delivery Service. Primary Delivery & Distribution Services REFUND.

Schedule Page: 328.3 Line No.: 27 Column: d

Evergreen Network Transmission Service under the Open Access Transmission Tariff (S.A. 175).

Schedule Page: 328.3 Line No.: 27 Column: m

December 2006 Service. Primary Delivery & Distribution Services REFUND.

Schedule Page: 328.3 Line No.: 28 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff, (S.A. 320) terminated on December 31, 2006 .

Schedule Page: 328.3 Line No.: 28 Column: m

Charges for monitoring, scheduling, load following and spinning reserve. Settlement adjustment. Distribution Service Charge. Primary Delivery Service. December 2006 Service.

Schedule Page: 328.3 Line No.: 30 Column: m

Represents the difference between actual wheeling revenues for the period as reflected on the individual line items within this schedule, and the accruals credited to account 456.1 during the period.

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(Next Page is 332)

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4			
TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565) (Including transactions referred to as "wheeling")								
<p>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.</p> <p>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.</p> <p>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.</p> <p>4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.</p> <p>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.</p> <p>6. Enter "TOTAL" in column (a) as the last line.</p> <p>7. Footnote entries and provide explanations following all required data.</p>								
Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Megawatt-hours Received (c)	Megawatt-hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	Arizona Public Service	AD	-17	-17	-224		8	-216
2	Arizona Public Service	LFP	164,048	164,048	924,960			924,960
3	Arizona Public Service	NF	9,163	9,163	32,000			32,000
4	Arizona Public Service	OS			18,766		32,426	51,192
5	Arizona Public Service	SFP	201,041	201,041	653,829			653,829
6	Ashland, City of	FNS	1,998	1,998		19,259		19,259
7	Avista Corp.	FNS	61,964	64,108	252,340			252,340
8	Avista Corp.	NF	24,904	24,904	66,772			66,772
9	Big Horn R. E. C.	AD					3	3
10	Big Horn R. E. C.	OS					48,606	48,606
11	Blanding City	LFP	71	71		426		426
12	Bonneville Power Adm.	AD	-3,541	-3,541	206,156	120,485	-373,639	-46,998
13	Bonneville Power Adm.	FNS			484,879		34,392	519,271
14	Bonneville Power Adm.	LFP	3,655,986	3,655,986	24,265,545	15,580		24,281,125
15	Bonneville Power Adm.	NF			184,236			184,236
16	Bonneville Power Adm.	OS	6,949,145	7,155,782	37,385,104	147,529	2,648,785	40,181,418
	TOTAL		15,280,202	15,548,183	83,966,265	2,028,269	20,597,577	106,592,111

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4					
TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565) (Including transactions referred to as "wheeling")								
<p>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.</p> <p>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.</p> <p>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.</p> <p>4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.</p> <p>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.</p> <p>6. Enter "TOTAL" in column (a) as the last line.</p> <p>7. Footnote entries and provide explanations following all required data.</p>								
Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Megawatt-hours Received (c)	Megawatt-hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	Bonneville Power Adm.	SFP			1,429,111		88,096	1,497,207
2	CAISO	AD				-3,146	182,000	178,854
3	CAISO	OS					5,653,238	5,653,238
4	CAISO	SFP	554,664	554,664		1,688,206		1,688,206
5	California PX	OS					15,738	15,738
6	Deseret P. E. C.	NF	8,351	8,351	30,224			30,224
7	Deseret P. E. C.	SFP	199,939	199,939	1,299,501			1,299,501
8	El Paso Elect. Co.	NF	31,872	31,872	55,995			55,995
9	El Paso Elect. Co.	SFP	150	150	326			326
10	Flathead Elect. Coop.	OS					58,223	58,223
11	Flowell Electric Assoc.	LFP	211	211	353			353
12	Hermiston Gen Co., L.P.	OS					165,355	165,355
13	Idaho Power Company	AD	-809,464	-809,464	-1,411,015			-1,411,015
14	Idaho Power Company	FNS			8,916			8,916
15	Idaho Power Company	NF	46,809	93,028	239,314	20,632		259,946
16	Idaho Power Company	OS					9,412,475	9,412,475
	TOTAL		15,280,202	15,548,183	83,966,265	2,028,269	20,597,577	106,592,111

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of <u>2007/Q4</u>
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TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Megawatt-hours Received (c)	Megawatt-hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	Idaho Power Company	SFP	407,031	407,031	1,128,762			1,128,762
2	LA Dept of Water & Pwr	NF	13,633	13,633	184,635			184,635
3	LA Dept of Water & Pwr	OS					10,083	10,083
4	LA Dept of Water & Pwr	SFP	1,645	1,645	15,354			15,354
5	MAPPCOR	AD					-6,802	-6,802
6	Moon Lake Elect. Assoc.	FNS					81,497	81,497
7	Morgan City	AD	15	15		171		171
8	Navajo Tribal Util Auth	OS					1,382	1,382
9	Nevada Power Company	NF	64,231	64,231	165,342			165,342
10	Nevada Power Company	OS					629,448	629,448
11	Nevada Power Company	SFP	988,561	988,561	3,120,317			3,120,317
12	NorthWestern Energy	AD					-86,015	-86,015
13	NorthWestern Energy	NF	65,162	65,496	294,554			294,554
14	NorthWestern Energy	OS					781,989	781,989
15	NorthWestern Energy	SFP	111,833	111,833	525,536			525,536
16	Platte River Power	AD					106	106
	TOTAL		15,280,202	15,548,183	83,966,265	2,028,269	20,597,577	106,592,111

Name of Respondent PacifiCorp			This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4		
TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565) (Including transactions referred to as "wheeling")								
<p>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.</p> <p>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.</p> <p>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.</p> <p>4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.</p> <p>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.</p> <p>6. Enter "TOTAL" in column (a) as the last line.</p> <p>7. Footnote entries and provide explanations following all required data.</p>								
Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Megawatt-hours Received (c)	Megawatt-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	Platte River Power	OS					10,861	10,861
2	Platte River Power	SFP	197,331	197,331	966,000			966,000
3	Portland Gen. Electric	NF	21	21	26			26
4	Portland Gen. Electric	OS	743,353	744,530			143,654	143,654
5	PSC of Colorado	LFP	110,725	116,457	849,844			849,844
6	PSC of New Mexico	AD			-83,691			-83,691
7	PSC of New Mexico	NF	976	976	8,853			8,853
8	PSC of New Mexico	OS					21,926	21,926
9	PSC of New Mexico	SFP	113,408	113,408	365,763			365,763
10	Salt River Project	SFP	7,368	7,368	18,455			18,455
11	Seattle City Light	NF	52,401	52,401	145,133			145,133
12	Sierra Pacific Power Co	NF	9,729	9,729	74,888			74,888
13	Sierra Pacific Power Co	OS					61,015	61,015
14	Sierra Pacific Power Co	SFP	5,613	5,613	576,000			576,000
15	Snohomish PUD No. 1	NF	208,146	208,146	469,323			469,323
16	Suprise Valley Electr.	OS					10,059	10,059
	TOTAL		15,280,202	15,548,183	83,966,265	2,028,269	20,597,577	106,592,111

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008		Year/Period of Report End of 2007/Q4		
TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565) (Including transactions referred to as "wheeling")								
<p>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.</p> <p>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.</p> <p>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.</p> <p>4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.</p> <p>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.</p> <p>6. Enter "TOTAL" in column (a) as the last line.</p> <p>7. Footnote entries and provide explanations following all required data.</p>								
Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Megawatt-hours Received (c)	Megawatt-hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	Tri-State Gen & Transm	LFP	113,973	119,711	849,844			849,844
2	Tri-State Gen & Transm	NF	21,582	21,582	62,773			62,773
3	Tri-State Gen & Transm	OS					11,064	11,064
4	Utah Assoc Muni Pwr Sys	AD					9,489	9,489
5	Utah Assoc Muni Pwr Sys	SFP	267,438	267,438	1,205,050		116,183	1,321,233
6	Western Area Power Adm.	AD			1,525		-11,693	-10,168
7	Western Area Power Adm.	FNS			3,538,166			3,538,166
8	Western Area Power Adm.	LFP	656,536	656,536	3,275,000			3,275,000
9	Western Area Power Adm.	NF	17,935	17,935	71,118			71,118
10	Western Area Power Adm.	OS				19,127	372,462	391,589
11	Western Area Power Adm.	SFP	4,262	4,262	10,607			10,607
12	Accrual True-up						495,163	495,163
13								
14								
15								
16								
TOTAL			15,280,202	15,548,183	83,966,265	2,028,269	20,597,577	106,592,111

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 332	Line No.: 1	Column: b
Settlement Adjustment		
Schedule Page: 332	Line No.: 1	Column: g
Ancillary Services		
Schedule Page: 332	Line No.: 4	Column: g
Ancillary Services and Use of Facilities		
Schedule Page: 332	Line No.: 9	Column: b
Settlement Adjustment		
Schedule Page: 332	Line No.: 9	Column: g
Use of Facilities		
Schedule Page: 332	Line No.: 10	Column: g
Use of Facilities		
Schedule Page: 332	Line No.: 12	Column: b
Settlement Adjustment		
Schedule Page: 332	Line No.: 12	Column: g
Ancillary Services and Use of Facilities		
Schedule Page: 332	Line No.: 13	Column: g
Use of Facilities		
Schedule Page: 332	Line No.: 16	Column: g
Ancillary Services and Use of Facilities		
Schedule Page: 332.1	Line No.: 1	Column: g
Reservation Fee		
Schedule Page: 332.1	Line No.: 2	Column: b
Settlement Adjustment		
Schedule Page: 332.1	Line No.: 2	Column: g
Ancillary Services		
Schedule Page: 332.1	Line No.: 3	Column: g
Ancillary Services		
Schedule Page: 332.1	Line No.: 5	Column: g
Ancillary Services		
Schedule Page: 332.1	Line No.: 10	Column: g
Use of Facilities		
Schedule Page: 332.1	Line No.: 12	Column: g
Use of Facilities		
Schedule Page: 332.1	Line No.: 13	Column: b
Settlement Adjustment		
Schedule Page: 332.1	Line No.: 16	Column: g
Ancillary Services and Use of Facilities and Respondent's Portion of Specified Costs of Certain Facilities		
Schedule Page: 332.2	Line No.: 3	Column: g
Ancillary Services		
Schedule Page: 332.2	Line No.: 5	Column: b
Settlement Adjustment		
Schedule Page: 332.2	Line No.: 5	Column: g
Patronage Refund		
Schedule Page: 332.2	Line No.: 6	Column: g
Use of Facilities		
Schedule Page: 332.2	Line No.: 7	Column: b
Settlement Adjustment		
Schedule Page: 332.2	Line No.: 8	Column: g
Use of Facilities		
Schedule Page: 332.2	Line No.: 10	Column: g

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Ancillary Services

Schedule Page: 332.2 Line No.: 12 Column: b

Settlement Adjustment

Schedule Page: 332.2 Line No.: 12 Column: g

Use of Facilities

Schedule Page: 332.2 Line No.: 14 Column: g

Ancillary Services and Use of Facilities and Respondent's portion of specified costs of certain facilities

Schedule Page: 332.2 Line No.: 16 Column: b

Settlement Adjustment

Schedule Page: 332.2 Line No.: 16 Column: g

Ancillary Services

Schedule Page: 332.3 Line No.: 1 Column: g

Ancillary Services

Schedule Page: 332.3 Line No.: 4 Column: g

Ancillary Services and Use of Facilities and Respondent's portion of specified costs of certain facilities

Schedule Page: 332.3 Line No.: 6 Column: b

Settlement Adjustment

Schedule Page: 332.3 Line No.: 8 Column: g

Ancillary Services

Schedule Page: 332.3 Line No.: 13 Column: g

Ancillary Services

Schedule Page: 332.3 Line No.: 16 Column: g

Use of Facilities

Schedule Page: 332.4 Line No.: 3 Column: g

Ancillary Services

Schedule Page: 332.4 Line No.: 4 Column: b

Settlement Adjustment

Schedule Page: 332.4 Line No.: 4 Column: g

Ancillary Services

Schedule Page: 332.4 Line No.: 5 Column: g

Ancillary Services

Schedule Page: 332.4 Line No.: 6 Column: b

Settlement Adjustment

Schedule Page: 332.4 Line No.: 6 Column: g

Ancillary Services and Use of Facilities

Schedule Page: 332.4 Line No.: 10 Column: g

Ancillary Services and Use of Facilities

Schedule Page: 332.4 Line No.: 12 Column: g

Represents the difference between the actual wheeling expenses for the period as reflected on the individual line items within this schedule, and the accruals charged to account 565 during this period.

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(Next Page is 335)

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)				
Line No.	Description (a)	Amount (b)		
1	Industry Association Dues	1,214,470		
2	Nuclear Power Research Expenses			
3	Other Experimental and General Research Expenses			
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities			
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < \$5,000			
6				
7	Community & Economic Development:			
8	Astoria Area Chamber of Commerce	5,000		
9	Cache Chamber of Commerce	5,000		
10	Del Norte Chamber of Commerce	6,000		
11	Economic Development Corp of Utah	166,066		
12	Economic Development for Central Oregon	9,000		
13	Klamath County Economic Development	12,810		
14	Laramie Economic Development Corp	5,000		
15	Laramie Regional Airport Board	5,000		
16	Oregon Economic Development Association	25,000		
17	Redmond Economic Development	7,500		
18	Rural Development Initiatives	5,000		
19	Siskiyou County Economic	35,000		
20	South Coast Development Council	7,500		
21	Southern Oregon Regional Economic	15,000		
22	State of Utah	10,000		
23	Utah Center for Rural Life	8,000		
24	Wallowa County Chamber of Commerce	5,000		
25	Other	38,520		
26				
27	Corporate Memberships and Subscriptions:			
28	Associated Oregon Industries	54,787		
29	California Climate Action Registry	20,000		
30	Idaho Mining Association	6,000		
31	Intermountain Electrical Association	7,500		
32	Linkville Kiwanis Club	5,605		
33	Manufacturing 21 Coalition	5,000		
34	Northern Tier Transmission Group	178,737		
35	NW Power & Conservancy	21,000		
36	Oregon Business Association	13,000		
37	Oregon Business Council	19,809		
38	Pacific Northwest Utilities Conference Committee	52,302		
39	Portland Business Alliance	39,050		
40	Rocky Mountain Electrical League	18,000		
41	Salt Lake Area Chamber of Commerce	30,255		
42	Utah Foundation	22,500		
43	Utah Manufacturers Association	6,000		
44	Utah Taxpayers Association	20,000		
45	Western Electricity Coordinating Council	1,854,300		
46	TOTAL	25,310,886		

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)				
Line No.	Description (a)	Amount (b)		
6	Western Energy Institute	40,000		
7	Wyoming Taxpayers Association	7,754		
8	Yakima County Development	5,000		
9	Other	116,655		
10				
11	Directors Fees - Regional Advisory Boards	170,588		
12				
13	Regulatory Asset Amortization:			
14	Glenrock Mine Stipulation-UT (Excluding Reclamation)	149,625		
15	Glenrock Mine 1998 Case-UT (Excluding Reclamation)	1,152,774		
16	98 Early Retirement- Oregon	3,676,946		
17	Transition Plan	3,892,299		
18	Utah Deferred Pension	3,159,014		
19				
20				
21	General:			
22	Thelen Reid & Priest LLP	10,000		
23	MEHC Cross Charge	8,949,915		
24	Legal Settlements	11,000		
25	Other	10,605		
26				
27				
28				
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45				
46	TOTAL	25,310,886		

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4			
DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405) (Except amortization of acquisition adjustments)						
<p>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).</p> <p>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.</p> <p>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.</p> <p>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.</p> <p>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.</p> <p>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.</p> <p>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.</p>						
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			42,032,755		42,032,755
2	Steam Production Plant	147,079,866				147,079,866
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	12,921,513		40,526		12,962,039
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	32,481,622		293,921		32,775,543
7	Transmission Plant	58,147,412				58,147,412
8	Distribution Plant	129,744,033				129,744,033
9	Regional Transmission and Market Operation					
10	General Plant	38,122,398		2,908,901		41,031,299
11	Common Plant-Electric					
12	TOTAL	418,496,844		45,276,103		463,772,947
B. Basis for Amortization Charges						
<p>The amortization of Limited-Term Electric Plant is based on straight-line amortization over the life of the asset.</p>						

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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	Hydraulic Prod Plant						
13	Clearwater #1 (42)						
14	336.00 OR	39			1.66		
15							
16	Other Production Plant						
17	Lake Side						
18	341.00 UT	41,901	35.00		2.86		
19	342.00 UT	3,274	35.00		2.86		
20	343.00 UT	162,289	35.00		2.86		
21	344.00 UT	75,291	35.00		2.86		
22	345.00 UT	40,592	35.00		2.86		
23	346.00 UT	2,946	35.00		2.86		
24							
25	Marengo Wind Plant						
26	341.00 WA	6,185	25.00		4.00		
27	343.00 WA	215,247	25.00		4.00		
28	344.00 WA	6,071	25.00		4.00		
29	345.00 WA	10,640	25.00		4.00		
30	346.00 WA	161	25.00		4.00		
31	347.00 WA	476	25.00		4.00		
32							
33	East Side Mobile						
34	344.00 UT	840	20.00		5.00		
35							
36							
37							
38							
39							
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Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 336 Line No.: 12 Column: b

Vehicle depreciation is charged to functional accounts. The following table summarizes the vehicle depreciation expense that was charged to the functional accounts.

	Twelve Months Ending December 31,	
	2007	2006
Vehicle Depreciation	\$12,494,116	\$12,268,419

Schedule Page: 336 Line No.: 14 Column: c

Not yet determined.

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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	Before the Public Service Commission of Utah:				
2	Annual Fee	3,396,652		3,396,652	
3	Other State Regulatory Expenses				
4					
5	Before the Public Utility Commission of				
6	Oregon:				
7	Annual Fee	2,471,043		2,471,043	
8	Other State Regulatory Expenses		555,488	555,488	
9					
10	Before the Public Service Commission of				
11	Wyoming:				
12	Annual Fee	891,463		891,463	
13	Other State Regulatory Expenses				
14					
15	Before the Washington Utilities and				
16	Transportation Commission:				
17	Annual Fee	440,568		440,568	
18	Other State Regulatory Expenses				
19					
20	Before the Idaho Public Utilities Commission:				
21	Annual Fee	328,764		328,764	
22	Other State Regulatory Expenses				
23					
24	Before the Public Utilities Commission of				
25	California:				
26	Annual Fee	5,250		5,250	
27	Other State Regulatory Expenses				
28					
29	Before the Federal Energy Regulatory				
30	Commission:				
31	Annual Fee	1,737,411		1,737,411	
32	Annual Land Use Fee	185,000		185,000	
33					
34	Deferred Regulatory Commission Expense				861,532
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	9,456,151	555,488	10,011,639	861,532

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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REGULATORY COMMISSION EXPENSES (Continued)

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

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Department (f)	Account No. (g)	Amount (h)					
							1
Electric	928	3,396,652					2
							3
							4
							5
							6
Electric	928	2,471,043					7
Electric	928	555,488					8
							9
							10
							11
Electric	928	891,463					12
							13
							14
							15
							16
Electric	928	440,568					17
							18
							19
							20
Electric	928	328,764					21
							22
							23
							24
							25
Electric	928	5,250					26
							27
							28
							29
							30
Electric	928	1,737,411					31
Electric	928	185,000					32
							33
			286,929	928	555,488	592,973	34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		10,011,639	286,929		555,488	592,973	46

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

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

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

- Classifications:
- A. Electric R, D & D Performed Internally:

(1) Generation

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

(2) Transmission

- a. Overhead
 - b. Underground

(3) Distribution

(4) Regional Transmission and Market Operation

(5) Environment (other than equipment)

(6) Other (Classify and include items in excess of \$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		
2		
3		
4	A. Electric R D&D Performed Internally	
5	(1) Generation	
6	b. Fossil-Fuel Steam	Integrated Gasification Combined Cycle
7		
8	B. Electric R D&D Performed Externally	
9	(1) Research Support	Electric Power Research Institute
10	(4) Research Support Others	B&W Advisory Work Group
11		
12		
13		
14		
15		
16		
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18		
19		
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Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

- (2) Research Support to Edison Electric Institute
 (3) Research Support to Nuclear Power Groups
 (4) Research Support to Others (Classify)
 (5) Total Cost Incurred
3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing \$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		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
					1
					2
					3
					4
					5
52,837	3,374,853	557	3,427,690		6
					7
					8
	1,217,789	930.2	1,217,789		9
	25,000	930.2	25,000		10
					11
					12
					13
					14
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Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/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	91,509,641			
4	Transmission	10,304,167			
5	Regional Market				
6	Distribution	45,354,610			
7	Customer Accounts	41,529,451			
8	Customer Service and Informational	4,751,499			
9	Sales				
10	Administrative and General	35,614,506			
11	TOTAL Operation (Enter Total of lines 3 thru 10)	229,063,874			
12	Maintenance				
13	Production	44,792,115			
14	Transmission	8,297,951			
15	Regional Market				
16	Distribution	68,489,947			
17	Administrative and General	2,847,405			
18	TOTAL Maintenance (Total of lines 13 thru 17)	124,427,418			
19	Total Operation and Maintenance				
20	Production (Enter Total of lines 3 and 13)	136,301,756			
21	Transmission (Enter Total of lines 4 and 14)	18,602,118			
22	Regional Market (Enter Total of Lines 5 and 15)				
23	Distribution (Enter Total of lines 6 and 16)	113,844,557			
24	Customer Accounts (Transcribe from line 7)	41,529,451			
25	Customer Service and Informational (Transcribe from line 8)	4,751,499			
26	Sales (Transcribe from line 9)				
27	Administrative and General (Enter Total of lines 10 and 17)	38,461,911			
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	353,491,292		353,491,292	
29	Gas				
30	Operation				
31	Production-Manufactured Gas				
32	Production-Nat. Gas (Including Expl. and Dev.)				
33	Other Gas Supply				
34	Storage, LNG Terminating 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 Terminating and Processing				
47	Transmission				

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
DISTRIBUTION OF SALARIES AND WAGES (Continued)					
Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)	
48	Distribution				
49	Administrative and General				
50	TOTAL Maint. (Enter Total of lines 43 thru 49)				
51	Total Operation and Maintenance				
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)				
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,				
54	Other Gas Supply (Enter Total of lines 33 and 45)				
55	Storage, LNG Terminating and Processing (Total of lines 31 thru				
56	Transmission (Lines 35 and 47)				
57	Distribution (Lines 36 and 48)				
58	Customer Accounts (Line 37)				
59	Customer Service and Informational (Line 38)				
60	Sales (Line 39)				
61	Administrative and General (Lines 40 and 49)				
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)				
63	Other Utility Departments				
64	Operation and Maintenance				
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	353,491,292		353,491,292	
66	Utility Plant				
67	Construction (By Utility Departments)				
68	Electric Plant	129,988,256		129,988,256	
69	Gas Plant				
70	Other (provide details in footnote):				
71	TOTAL Construction (Total of lines 68 thru 70)	129,988,256		129,988,256	
72	Plant Removal (By Utility Departments)				
73	Electric Plant	10,177,515		10,177,515	
74	Gas Plant				
75	Other (provide details in footnote):				
76	TOTAL Plant Removal (Total of lines 73 thru 75)	10,177,515		10,177,515	
77	Other Accounts (Specify, provide details in footnote):				
78	Fuel Stock	23,521,098		23,521,098	
79	Miscellaneous Income Deduction	265,978		265,978	
80	Miscellaneous Nonoperating / Nonutility	864,593		864,593	
81					
82					
83					
84					
85					
86					
87					
88					
89					
90					
91					
92					
93					
94					
95	TOTAL Other Accounts	24,651,669		24,651,669	
96	TOTAL SALARIES AND WAGES	518,308,732		518,308,732	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM:

Line No.	Month	Monthly Peak MW - Total	Day of Monthly Peak	Hour of Monthly Peak	Firm Network Service for Self	Firm Network Service for Others	Long-Term Firm Point-to-point Reservations	Other Long-Term Firm Service	Short-Term Firm Point-to-point Reservation	Other Service
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	January	13,653	16	800	8,644	746	4,153		110	
2	February	13,814	2	800	8,432	707	4,450		225	
3	March	13,867	1	1900	7,809	715	4,968		375	
4	Total for Quarter 1	41,334			24,885	2,168	13,571		710	
5	April	14,174	30	1500	7,037	740	4,968		1,429	
6	May	15,475	31	1700	7,804	802	4,968		1,901	
7	June	17,924	20	1700	8,886	964	5,662		2,412	
8	Total for Quarter 2	47,573			23,727	2,506	15,598		5,742	
9	July	19,150	10	1700	9,775	1,053	5,933		2,389	
10	August	18,694	14	1700	9,405	1,088	5,926		2,275	
11	September	17,035	4	1600	8,254	957	6,004		1,820	
12	Total for Quarter 3	54,879			27,434	3,098	17,863		6,484	
13	October	15,772	4	2000	7,081	721	6,054		1,916	
14	November	16,940	28	1800	8,395	758	5,201		2,586	
15	December	17,047	11	1900	8,633	843	5,201		2,370	
16	Total for Quarter 4	49,759			24,109	2,322	16,456		6,872	
17	Total Year to Date/Year	193,545			100,155	10,094	63,488		19,808	

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 400 Line No.: 1 Column: b

Reflects actual demands of control area load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 1 Column: e

Reflects actual demands of control area load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 3 Column: b

Reflects actual demands of control area load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 3 Column: e

Reflects actual demands of control area load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 4 Column: e

Reflects actual demands of control area load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 4 Column: g

Reflects reservations in effect at time of Transmission System Peak

Schedule Page: 400 Line No.: 4 Column: i

Reflects reservations in effect at time of Transmission System Peak

Schedule Page: 400 Line No.: 5 Column: b

Reflects actual demands of control area load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 5 Column: e

Reflects actual demands of control area load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 6 Column: b

Reflects actual demands of control area load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 6 Column: e

Reflects actual demands of control area load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 7 Column: b

Reflects actual demands of control area load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 7 Column: g

Reflects actual demands of control area load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 8 Column: e

Reflects actual demands of control area load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 8 Column: g

Reflects reservations in effect at time of Transmission System Peak

Schedule Page: 400 Line No.: 8 Column: i

Reflects reservations in effect at time of Transmission System Peak

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

Reflects actual demands of control area load at time of Transmission System Peak.

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

Reflects actual demands of control area load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 11 Column: b

Reflects actual demands of control area load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 11 Column: e

Reflects actual demands of control area load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 12 Column: e

Reflects actual demands of control area load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 12 Column: g

Reflects reservations in effect at time of Transmission System Peak

Schedule Page: 400 Line No.: 12 Column: i

Reflects reservations in effect at time of Transmission System Peak

Schedule Page: 400 Line No.: 16 Column: e

Reflects actual demands of control area load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 16 Column: g

Reflects reservations in effect at time of Transmission System Peak

Schedule Page: 400 Line No.: 16 Column: i

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Reflects reservations in effect at time of Transmission System Peak

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
ELECTRIC ENERGY ACCOUNT					
Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.					
Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	53,390,478
3	Steam	48,172,013	23	Requirements Sales for Resale (See instruction 4, page 311.)	209,695
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	13,514,160
5	Hydro-Conventional	3,748,868	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage	-4,963	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	161,514
7	Other	6,271,889	27	Total Energy Losses	4,498,827
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	71,774,674
9	Net Generation (Enter Total of lines 3 through 8)	58,187,807			
10	Purchases	13,186,772			
11	Power Exchanges:				
12	Received	9,646,444			
13	Delivered	8,978,368			
14	Net Exchanges (Line 12 minus line 13)	668,076			
15	Transmission For Other (Wheeling)				
16	Received	16,933,144			
17	Delivered	16,933,144			
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses	-267,981			
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	71,774,674			

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MONTHLY PEAKS AND OUTPUT						
<p>(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.</p> <p>(2) Report on line 2 by month the system's output in Megawatt hours for each month.</p> <p>(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.</p> <p>(4) Report on line 4 by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.</p> <p>(5) Report on lines 5 and 6 the specified information for each monthly peak load reported on line 4.</p>						
NAME OF SYSTEM:						
Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirements Sales for Resale & Associated Losses (c)	MONTHLY PEAK		
				Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	6,455,577	1,100,247	8,644	16	0800 PST
30	February	5,597,827	1,098,403	8,433	2	0800 PST
31	March	5,781,156	1,252,368	7,809	1	1900 PST
32	April	5,498,254	1,267,323	7,037	30	1500 PST
33	May	5,623,927	1,015,163	7,804	31	1700 PDT
34	June	6,030,551	1,156,601	8,887	20	1700 PDT
35	July	6,484,867	954,615	9,775	10	1700 PDT
36	August	6,456,293	1,086,826	9,406	14	1700 PDT
37	September	5,568,789	1,035,092	8,254	4	1600 PST
38	October	5,873,734	1,241,151	7,144	31	0800 PST
39	November	5,964,772	1,183,998	8,395	28	1800 PST
40	December	6,438,927	1,122,373	8,650	11	1800 PST
41	TOTAL	71,774,674	13,514,160			

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	Plant Name: <i>Carbon</i> (b)	Plant Name: <i>Cholla</i> (c)				
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Steam	Steam				
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor Boiler	Full Outdoor				
3	Year Originally Constructed	1954	1981				
4	Year Last Unit was Installed	1957	1981				
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	188.60	414.00				
6	Net Peak Demand on Plant - MW (60 minutes)	174	370				
7	Plant Hours Connected to Load	8661	8432				
8	Net Continuous Plant Capability (Megawatts)	0	0				
9	When Not Limited by Condenser Water	172	380				
10	When Limited by Condenser Water	0	0				
11	Average Number of Employees	69	0				
12	Net Generation, Exclusive of Plant Use - KWh	1339343000	2882441000				
13	Cost of Plant: Land and Land Rights	956546	1246363				
14	Structures and Improvements	12437266	53032033				
15	Equipment Costs	78212060	332222865				
16	Asset Retirement Costs	1852187	39000				
17	Total Cost	93458059	386540261				
18	Cost per KW of Installed Capacity (line 17/5) Including	495.5358	933.6721				
19	Production Expenses: Oper, Supv, & Engr	101996	1310396				
20	Fuel	16105801	52166876				
21	Coolants and Water (Nuclear Plants Only)	0	0				
22	Steam Expenses	1136931	2053090				
23	Steam From Other Sources	0	0				
24	Steam Transferred (Cr)	0	0				
25	Electric Expenses	1917701	1320614				
26	Misc Steam (or Nuclear) Power Expenses	4730820	1603350				
27	Rents	16554	116165				
28	Allowances	0	0				
29	Maintenance Supervision and Engineering	0	1786866				
30	Maintenance of Structures	224407	862871				
31	Maintenance of Boiler (or reactor) Plant	1973419	3997568				
32	Maintenance of Electric Plant	708098	797219				
33	Maintenance of Misc Steam (or Nuclear) Plant	373684	2556029				
34	Total Production Expenses	27289411	68571044				
35	Expenses per Net KWh	0.0204	0.0238				
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil	Composite	Coal	Oil	Composite
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		Tons	Barrels	
38	Quantity (Units) of Fuel Burned	640585	3347	0	1591193	2213	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12115	140000	0	9652	134879	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	24.393	99.736	0.000	31.712	76.664	0.000
41	Average Cost of Fuel per Unit Burned	24.621	0.000	0.000	32.678	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	1.016	16.962	1.036	1.693	13.534	1.698
43	Average Cost of Fuel Burned per KWh Net Gen	0.011	0.000	0.011	0.017	0.000	0.017
44	Average BTU per KWh Net Generation	11588.569	14.696	11603.265	10656.382	4.349	10660.731

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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: <u>Colstrip</u> (d)			Plant Name: <u>Craig</u> (e)			Plant Name: <u>Dave Johnston</u> (f)			Line No.
Steam			Steam			Steam			1
Conventional			Outdoor Boiler			Semi-Outdoor			2
1984			1979			1959			3
1986			1980			1972			4
155.60			172.10			816.80			5
156			166			758			6
8688			8760			8753			7
0			0			0			8
148			165			762			9
0			0			0			10
0			0			191			11
1121294000			1321920000			5696860000			12
1355853			137086			10451083			13
57295720			35664260			50697737			14
154125100			128813062			383610279			15
39236			55971			6594275			16
212815909			164670379			451353374			17
1367.7115			956.8296			552.5874			18
18469			307791			695975			19
11971061			17534561			42371196			20
0			0			0			21
859624			1417066			0			22
0			0			0			23
0			0			0			24
27780			519891			0			25
1250201			512220			14956185			26
19912			7876			212751			27
0			0			0			28
285382			558068			0			29
299432			312175			2345496			30
2525565			2917679			8945570			31
449303			821158			7651191			32
360326			696158			1554039			33
18067055			25604643			78732403			34
0.0161			0.0194			0.0138			35
Coal	Oil	Composite	Coal	Oil	Gas	Coal	Oil	Composite	36
Tons	Barrels		Tons	Barrels	MCF	Tons	Barrels		37
708786	2064	0	667842	457	7392	3942421	6299	0	38
8437	140000	0	9998	122360	1087	8052	140000	0	39
15.803	97.005	0.000	24.755	111.901	0.000	10.515	95.166	0.000	40
16.607	0.000	0.000	26.138	0.000	3.686	10.595	0.000	0.000	41
0.984	16.497	1.000	1.307	21.771	0.420	0.658	16.185	0.667	42
0.010	0.000	0.010	0.013	0.000	0.000	0.007	0.000	0.007	43
10666.294	10.821	10677.115	10102.098	1.778	49.065	11145.142	6.501	11151.643	44

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

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

Line No.	Item	Plant Name: <u>Hayden</u>			Plant Name: <u>Hunter Unit No. 1</u>		
	(a)	(b)			(c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor Boiler			Outdoor Boiler		
3	Year Originally Constructed	1965			1978		
4	Year Last Unit was Installed	1976			1978		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	81.30			443.00		
6	Net Peak Demand on Plant - MW (60 minutes)	79			411		
7	Plant Hours Connected to Load	8760			8231		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	78			403		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			74		
12	Net Generation, Exclusive of Plant Use - KWh	648900000			3035550000		
13	Cost of Plant: Land and Land Rights	379735			9688975		
14	Structures and Improvements	6002332			61926142		
15	Equipment Costs	61039177			229829854		
16	Asset Retirement Costs	20877			1062923		
17	Total Cost	67442121			302507894		
18	Cost per KW of Installed Capacity (line 17/5) Including	829.5464			682.8621		
19	Production Expenses: Oper, Supv, & Engr	156722			-1		
20	Fuel	11195910			37892177		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	954756			2925851		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	204688			0		
26	Misc Steam (or Nuclear) Power Expenses	402400			2633887		
27	Rents	0			1522		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	240420			0		
30	Maintenance of Structures	145459			1975615		
31	Maintenance of Boiler (or reactor) Plant	838026			5620197		
32	Maintenance of Electric Plant	193556			795557		
33	Maintenance of Misc Steam (or Nuclear) Plant	370093			221234		
34	Total Production Expenses	14702030			52066039		
35	Expenses per Net KWh	0.0227			0.0172		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil	Gas	Coal	Oil	Composite
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels	MCF	Tons	Barrels	
38	Quantity (Units) of Fuel Burned	314700	376	9605	1479754	5013	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11230	132579	1091	11290	140000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	33.429	96.684	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	35.466	0.000	-0.172	25.266	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	1.579	17.361	-0.039	1.119	17.139	1.133
43	Average Cost of Fuel Burned per KWh Net Gen	0.016	0.000	0.000	0.012	0.000	0.012
44	Average BTU per KWh Net Generation	10892.524	3.229	65.582	11007.179	9.710	11016.889

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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: <u>Hunter Unit No. 2</u> (d)	Plant Name: <u>Hunter Unit No. 3</u> (e)	Plant Name: <u>Hunter - Total Plant</u> (f)	Line No.						
Steam									
Outdoor Boiler									
1980	1983	1978	1						
1980	1983	1983	2						
285.00	495.60	1223.60	3						
264	483	1130	4						
8405	7017	8760	5						
0	0	0	6						
259	460	1122	7						
0	0	0	8						
74	74	222	9						
2052174000	2950942000	8038666000	10						
9688975	10275401	29653351	11						
50727551	89910667	202564360	12						
153309304	402956162	786095320	13						
1062923	1062923	3188769	14						
214788753	504205153	1021501800	15						
753.6447	1017.3631	834.8331	16						
-1	-1	-3	17						
24841550	34651787	97385514	18						
0	0	0	19						
2946653	2937596	8810100	20						
0	0	0	21						
0	0	0	22						
0	0	0	23						
139052	3070682	5843621	24						
1522	2691	5735	25						
0	0	0	26						
0	0	0	27						
1828705	2229888	6034208	28						
4665389	12660913	22946499	29						
937187	3711889	5444633	30						
117679	119882	458795	31						
35477736	59385327	146929102	32						
0.0173	0.0201	0.0183	33						
Coal	Oil	Composite	Coal	Oil	Composite	Coal	Oil	Composite	
Tons	Barrels		Tons	Barrels		Tons	Barrels		
970140	1662	0	1329439	21173	0	3779332	27848	0	
11356	140000	0	11260	140000	0	11296	140000	0	
0.000	0.000	0.000	0.000	0.000	0.000	25.272	99.112	0.000	
25.437	0.000	0.000	24.492	0.000	0.000	25.038	0.000	0.000	
1.120	16.816	1.127	1.088	16.792	1.153	1.108	16.856	1.138	
0.012	0.000	0.012	0.011	0.001	0.012	0.012	0.000	0.012	
10736.814	4.763	10741.576	10145.560	42.190	10187.750	10621.863	20.370	10642.233	

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

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

Line No.	Item (a)	Plant Name: <i>Huntington</i> (b)	Plant Name: <i>Jim Bridger</i> (c)				
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Steam	Steam				
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor Boiler	Semi-Outdoor				
3	Year Originally Constructed	1974	1974				
4	Year Last Unit was Installed	1977	1979				
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	996.00	1541.10				
6	Net Peak Demand on Plant - MW (60 minutes)	918	1414				
7	Plant Hours Connected to Load	8759	8759				
8	Net Continuous Plant Capability (Megawatts)	0	0				
9	When Not Limited by Condenser Water	895	1413				
10	When Limited by Condenser Water	0	0				
11	Average Number of Employees	163	341				
12	Net Generation, Exclusive of Plant Use - KWh	7127084000	10054697000				
13	Cost of Plant: Land and Land Rights	2386782	1161925				
14	Structures and Improvements	112015877	134968247				
15	Equipment Costs	507906766	785821165				
16	Asset Retirement Costs	2505034	6663361				
17	Total Cost	624814459	928614698				
18	Cost per KW of Installed Capacity (line 17/5) Including	627.3238	602.5662				
19	Production Expenses: Oper, Supv, & Engr	13432	17855550				
20	Fuel	82679450	139077086				
21	Coolants and Water (Nuclear Plants Only)	0	0				
22	Steam Expenses	7926745	3807725				
23	Steam From Other Sources	0	0				
24	Steam Transferred (Cr)	0	0				
25	Electric Expenses	0	8038				
26	Misc Steam (or Nuclear) Power Expenses	10301575	-16196118				
27	Rents	34384	432434				
28	Allowances	0	0				
29	Maintenance Supervision and Engineering	1380545	843513				
30	Maintenance of Structures	1602737	7909487				
31	Maintenance of Boiler (or reactor) Plant	6275922	29006788				
32	Maintenance of Electric Plant	1298451	7703496				
33	Maintenance of Misc Steam (or Nuclear) Plant	1263732	2144172				
34	Total Production Expenses	112776973	192592171				
35	Expenses per Net KWh	0.0158	0.0192				
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil	Composite	Coal	Oil	Composite
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		Tons	Barrels	
38	Quantity (Units) of Fuel Burned	3221777	8997	0	5709196	29450	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11318	140000	0	9136	140000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	25.534	98.288	0.000	23.981	90.283	0.000
41	Average Cost of Fuel per Unit Burned	25.388	0.000	0.000	23.894	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	1.122	16.716	1.133	1.308	15.354	1.331
43	Average Cost of Fuel Burned per KWh Net Gen	0.011	0.000	0.011	0.014	0.000	0.014
44	Average BTU per KWh Net Generation	10232.762	7.423	10240.184	10375.008	17.222	10392.230

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

Plant Name: <i>Naughton</i> (d)			Plant Name: <i>Wyodak</i> (e)			Plant Name: <i>Gadsby Steam Plant</i> (f)			Line No.
Steam			Steam			Steam			1
Outdoor Boiler			Conventional			Outdoor			2
1963			1978			1951			3
1971			1978			1955			4
707.20			289.70			257.60			5
706			278			194			6
8760			8600			3520			7
0			0			0			8
700			268			235			9
0			0			0			10
140			72			37			11
5210618000			2256168000			305832000			12
4290794			210526			1252090			13
64349044			47920904			14068046			14
323952614			271746601			56537656			15
2841694			761616			676487			16
395434146			320639647			72534279			17
559.1546			1106.7989			281.5772			18
435688			558023			39175			19
77343857			18167354			26414704			20
0			0			0			21
6809204			0			379			22
0			0			0			23
0			0			0			24
9184			0			0			25
9409653			4081478			3325222			26
2000			9934			0			27
0			0			0			28
1104599			614			0			29
1964606			497413			157495			30
8573325			4922299			1227508			31
3422281			958974			939500			32
980042			554950			572389			33
110054439			29751039			32676372			34
0.0211			0.0132			0.1068			35
Coal	Gas	Composite	Coal	Oil	Composite	Gas			36
Tons	MCF		Tons	Barrels		MCF			37
2772108	188191	0	1651101	3340	0	4118910	0	0	38
9929	1065	0	7830	140000	0	1053	0	0	39
27.456	0.000	0.000	10.808	94.502	0.000	0.000	0.000	0.000	40
27.461	6.478	0.000	10.812	0.000	0.000	6.413	0.000	0.000	41
1.383	6.311	1.400	0.690	16.072	0.702	6.093	0.000	0.000	42
0.015	0.000	0.015	0.008	0.000	0.008	0.086	0.000	0.000	43
10565.099	37.070	10602.169	11460.245	8.705	11468.949	14176.352	0.000	0.000	44

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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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: <i>Little Mountain</i> (b)	Plant Name: <i>Hermiston</i> (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Gas Turbine	Combined Cycle
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor Boiler	Outdoor
3	Year Originally Constructed	1972	1996
4	Year Last Unit was Installed	1972	1996
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	16.00	279.60
6	Net Peak Demand on Plant - MW (60 minutes)	17	245
7	Plant Hours Connected to Load	8302	8560
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	14	237
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	6	0
12	Net Generation, Exclusive of Plant Use - KWh	112602000	1711346000
13	Cost of Plant: Land and Land Rights	635	842245
14	Structures and Improvements	217599	12522919
15	Equipment Costs	5071833	153242645
16	Asset Retirement Costs	0	214373
17	Total Cost	5290067	166822182
18	Cost per KW of Installed Capacity (line 17/5) Including	330.6292	596.6459
19	Production Expenses: Oper, Supv, & Engr	0	0
20	Fuel	11906700	52038225
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	955208	7791207
26	Misc Steam (or Nuclear) Power Expenses	0	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Steam (or Nuclear) Plant	59927	0
34	Total Production Expenses	12921835	59829432
35	Expenses per Net KWh	0.1148	0.0350
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas	Gas
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF	MCF
38	Quantity (Units) of Fuel Burned	1945941	12139569
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1014	1022
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000
41	Average Cost of Fuel per Unit Burned	6.119	4.287
42	Average Cost of Fuel Burned per Million BTU	6.034	4.195
43	Average Cost of Fuel Burned per KWh Net Gen	0.106	0.030
44	Average BTU per KWh Net Generation	17523.552	7248.468

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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: <u>Blundell</u> (d)	Plant Name: <u>Camas Co-Gen</u> (e)	Plant Name: <u>West Valley</u> (f)	Line No.
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Steam - Geothermal	Steam	Gas Turbine	Line
Indoor	Outdoor Boiler	Outdoor	
1984	1996	2002	1
2007	1996	2002	2
38.10	61.50	217.00	3
37	46	215	4
7038	7303	5947	5
0	0	0	6
34	22	202	7
0	0	0	8
15	0	8	9
163875000	121849000	667031000	10
41195596	0	0	11
6698624	5733734	116354	12
64426128	28716806	622401	13
1336278	0	0	14
113656626	34450540	738755	15
2983.1135	560.1714	3.4044	16
31426	0	0	17
0	0	41701673	18
0	0	0	19
-8229	0	0	20
4845079	0	0	21
0	0	0	22
0	0	8999446	23
1579607	20366	0	24
1458	0	10977690	25
0	0	0	26
0	0	0	27
158507	0	92698	28
319944	0	0	29
1450796	0	624790	30
66958	777	136817	31
8445546	21143	62533114	32
0.0515	0.0002	0.0937	33
		Gas	34
		MCF	35
0	0	0	36
0	0	0	37
0.000	0.000	0.000	38
0.000	0.000	0.000	39
0.000	0.000	0.000	40
0.000	0.000	0.000	41
0.000	0.000	0.000	42
0.000	0.000	0.000	43
0.000	0.000	0.000	44

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

Line No.	Item (a)	Plant Name: <i>Gadsby Gas Peakers</i> (b)	Plant Name: <i>Currant Creek</i> (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine	Combined Cycle
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor	Outdoor
3	Year Originally Constructed	2002	2005
4	Year Last Unit was Installed	2002	2006
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	141.00	566.90
6	Net Peak Demand on Plant - MW (60 minutes)	124	568
7	Plant Hours Connected to Load	5110	8370
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	120	540
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	0	21
12	Net Generation, Exclusive of Plant Use - KWh	327217000	3605071000
13	Cost of Plant: Land and Land Rights	0	3403030
14	Structures and Improvements	4121643	42374901
15	Equipment Costs	71981641	294996242
16	Asset Retirement Costs	0	134848
17	Total Cost	76103284	340909021
18	Cost per KW of Installed Capacity (line 17/5) Including	539.7396	601.3565
19	Production Expenses: Oper, Supv, & Engr	0	698439
20	Fuel	22993864	151425146
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	1636826	1819594
26	Misc Steam (or Nuclear) Power Expenses	0	16093
27	Rents	0	2123
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	183422	323875
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	646701	2813553
33	Maintenance of Misc Steam (or Nuclear) Plant	145817	51664
34	Total Production Expenses	25606630	157150487
35	Expenses per Net KWh	0.0783	0.0436
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas	Gas
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF	MCF
38	Quantity (Units) of Fuel Burned	3736433 0 0	24810285 0 0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1047 0 0	1045 0 0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000 0.000 0.000	0.000 0.000 0.000
41	Average Cost of Fuel per Unit Burned	6.154 0.000 0.000	6.103 0.000 0.000
42	Average Cost of Fuel Burned per Million BTU	5.879 0.000 0.000	5.842 0.000 0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.070 0.000 0.000	0.042 0.000 0.000
44	Average BTU per KWh Net Generation	11952.719 0.000 0.000	7189.511 0.000 0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)											
<p>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.</p>											
Plant Name: Lake Side (d)			Plant Name: (e)			Plant Name: (f)			Line No.		
Combined Cycle									1		
Outdoor									2		
2007									3		
2007									4		
548.00			0.00			0.00			5		
594			0			0			6		
2482			0			0			7		
0			0			0			8		
548			0			0			9		
0			0			0			10		
21			0			0			11		
1185861000			0			0			12		
17296760			0			0			13		
41901000			0			0			14		
284392458			0			0			15		
0			0			0			16		
343590218			0			0			17		
626.9894			0.0000			0.0000			18		
31314			0			0			19		
45771901			0			0			20		
0			0			0			21		
0			0			0			22		
0			0			0			23		
0			0			0			24		
1253357			0			0			25		
0			0			0			26		
0			0			0			27		
0			0			0			28		
0			0			0			29		
15979			0			0			30		
0			0			0			31		
545625			0			0			32		
1081			0			0			33		
47619257			0			0			34		
0.0402			0.0000			0.0000			35		
Gas									36		
MCF									37		
7761318			0			0			38		
1050			0			0			39		
0.000			0.000			0.000			40		
5.897			0.000			0.000			41		
5.616			0.000			0.000			42		
0.039			0.000			0.000			43		
6873.149			0.000			0.000			44		

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
PacifiCorp			
FOOTNOTE DATA			

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

Cholla

The Cholla Plant is operated by Arizona Public Service Company. Respondent owns Unit No. 4 plus 36.12% of related common facilities. Data reported represents respondent's share. PacifiCorp does not have employees at the Cholla Plant.

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

Colstrip

The Colstrip Plant is operated by PPL Montana, LLC and is jointly owned. Data reported represents respondent's 10% share of Colstrip Plant Units No. 3 and No. 4. PacifiCorp does not have employees at the Colstrip Plant.

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

Craig

The Craig Plant is operated by Tri-State Generation and Transmission Association and is jointly owned. Data reported represents respondent's 19.28% share of Craig Plant Units No. 1 and No. 2 and 12.86% of common facilities. PacifiCorp does not have employees at the Craig Plant.

Schedule Page: 402.1 Line No.: -1 Column: b

Hayden

The Hayden Plant is operated by Public Service Company of Colorado and is jointly owned. Data reported represents respondent's 24.5% (45 MW) share of Hayden Unit No. 1, 12.6% (33 MW) share of Hayden Unit No. 2 and 17.5% of common facilities. PacifiCorp does not have employees at the Hayden Plant.

Schedule Page: 402.1 Line No.: -1 Column: c

Hunter Plant Unit No. 1

Hunter Plant Unit No. 1 is owned by the respondent and Provo City Corporation with an undivided interest of 93.75% and 6.25%, respectively. Data reported in column (c) represents respondent's share. Costs to operate and maintain this unit are charged to appropriate FERC accounts. Costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this unit for calendar year 2007 was \$1.1 million and was primarily charged to account 506.

Schedule Page: 402.1 Line No.: -1 Column: d

Hunter Plant Unit No. 2

Hunter Plant Unit No. 2 is owned by the respondent, Deseret Power Electric Cooperative and Utah Associated Municipal Power Systems. Each with an undivided interest of 60.31%, 25.108% and 14.582% respectively. Data reported in column (d) represents respondent's share. Costs to operate and maintain this unit are charged to appropriate FERC accounts, costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this unit for calendar year 2007 was \$6.1 million and was primarily charged to account 506.

Schedule Page: 402.1 Line No.: -1 Column: f

Hunter

Hunter Unit No. 1 is owned by the respondent and Provo City Corporation with an undivided interest of 93.75% and 6.25% respectively. Hunter Unit No. 2 is owned by the respondent, Deseret Power Electric Cooperative and Utah Associated Municipal Power Systems. Each with an undivided interest of 60.31%, 25.108% and 14.582% respectively. Data in column (f) represents respondent's share. Costs to operate and maintain this plant are charged to appropriate FERC accounts, costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this plant for calendar year 2007 was \$7.2 million and was primarily charged to account 506.

Schedule Page: 402.2 Line No.: -1 Column: c

Jim Bridger

Jim Bridger Plant is operated by PacifiCorp and column (c) represents the respondent's share. Ownership of the plant is as follows: PacifiCorp 66 2/3%, Idaho Power Company 33 1/3%. Costs to operate and maintain this plant are charged to appropriate FERC accounts, costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this plant for calendar year 2007 was \$27.5 million and was primarily charged to account 506.

Schedule Page: 402.2 Line No.: -1 Column: e

Wyodak

Wyodak Plant is operated by PacifiCorp and column (e) represents the respondent's share. Ownership of the plant is as follows: PacifiCorp 80%, Black Hills Corporation 20%. Costs to operate and maintain this plant are charged to appropriate FERC accounts, costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this plant for calendar year 2007 was \$3.4 million and was primarily charged to account 506.

Schedule Page: 402.3 Line No.: -1 Column: c

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FOOTNOTE DATA			

Hermiston

The Hermiston Plant is operated by Hermiston Operating Company, L.P. and is jointly owned. Data reported on lines 5 through 43 represent's the respondent's 50.0% share of the Hermiston Plant. See Page 326- Purchased Power of this Form No. 1 for further information on Hermiston Generating Company, L.P. PacifiCorp does not have any employees at the Hermiston Plant.

Schedule Page: 402.3 Line No.: -1 Column: d

Blundell

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards. For further information regarding the Blundell generating facility, refer to Page 108, *Important Changes During the Year*, Item 2, of this Form No. 1.

In 2007, PacifiCorp added Unit 2, a 10.7 MW bottoming cycle, to the Blundell generating facility.

Schedule Page: 402.3 Line No.: -1 Column: e

Camas Co-Gen

PacifiCorp owns the steam turbine generator and associated systems directly related to the operation of this unit at Georgia-Pacific Corporation's Camas, Washington paper mill. Modifications and upgrades to the existing Camas paper mill were necessary to supply steam to the turbine and to ensure continued operation of the unit in the event of mill closure. Georgia-Pacific retained ownership of these modifications. Georgia-Pacific supplies the fuel and delivers the steam to PacifiCorp's turbine. PacifiCorp is responsible for major maintenance costs only on the repair of the turbine generator and auxiliary equipment. None of the facilities are jointly owned. Each asset is wholly owned, either by PacifiCorp or Georgia-Pacific Corporation. PacifiCorp does not have employees at the Camas Paper Mill.

Schedule Page: 402.3 Line No.: -1 Column: f

West Valley

In May 2002, PacifiCorp entered into a 15-year operating lease for an electric generation facility with West Valley Leasing Company, LLC ("West Valley"). West Valley is an indirect subsidiary of PacifiCorp's former parent ScottishPower PLC. The facility consists of five generation units; each rated at 40 megawatts ("MW"), and is located in Utah. The lease terms granted PacifiCorp two independent early termination options that provide PacifiCorp the right to terminate the lease and, at PacifiCorp's further option, to purchase the facility for predetermined amounts. On May 28, 2004, PacifiCorp exercised its first option to terminate the lease and subsequently exercised its right to rescind the termination on September 28, 2004. On December 1, 2006, PacifiCorp waived its option to purchase the facility under the lease for \$122.5 million and exercised its second option to terminate the lease. As such, PacifiCorp made lease payments of \$10.0 million for the year ending December 31, 2007 and is committed to future minimum lease payments of \$4.4 million for the year ending December 31, 2008.

Schedule Page: 402 Line No.: 42 Column: e3

The Craig Plant operates on coal with start up provided by oil and natural gas. The composite rate is 1.307.

Schedule Page: 402 Line No.: 43 Column: e3

The Craig Plant operates on coal with start up provided by oil and natural gas. The composite rate is 0.013.

Schedule Page: 402 Line No.: 44 Column: e3

The Craig Plant operates on coal with start up provided by oil and natural gas. The composite rate is 10,152.941.

Schedule Page: 402.1 Line No.: 42 Column: b3

The Hayden Plant operates on coal with start up provided by oil and natural gas. The composite rate is 1.574.

Schedule Page: 402.1 Line No.: 43 Column: b3

The Hayden Plant operates on coal with start up provided by oil and natural gas. The composite rate is 0.016.

Schedule Page: 402.1 Line No.: 44 Column: b3

The Hayden Plant operates on coal with start up provided by oil and natural gas. The composite rate is 10,961.335.

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/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. 2082 Plant Name: Copco No. 1 (b)		FERC Licensed Project No. 2082 Plant Name: Copco No. 2 (c)	
1	Kind of Plant (Run-of-River or Storage)	Storage		Run-of-River	
2	Plant Construction type (Conventional or Outdoor)	Conventional		Conventional	
3	Year Originally Constructed	1918		1925	
4	Year Last Unit was Installed	1922		1925	
5	Total installed cap (Gen name plate Rating in MW)	20.00		27.00	
6	Net Peak Demand on Plant-Megawatts (60 minutes)	25		32	
7	Plant Hours Connect to Load	6,632		6,459	
8	Net Plant Capability (in megawatts)				
9	(a) Under Most Favorable Oper Conditions	28		34	
10	(b) Under the Most Adverse Oper Conditions	28		34	
11	Average Number of Employees	1		2	
12	Net Generation, Exclusive of Plant Use - Kwh	95,316,000		119,854,000	
13	Cost of Plant				
14	Land and Land Rights	180,375		20,914	
15	Structures and Improvements	1,228,623		1,642,177	
16	Reservoirs, Dams, and Waterways	2,637,394		2,922,163	
17	Equipment Costs	4,629,582		4,352,405	
18	Roads, Railroads, and Bridges	105,442		240,200	
19	Asset Retirement Costs	0		0	
20	TOTAL cost (Total of 14 thru 19)	8,781,416		9,177,859	
21	Cost per KW of Installed Capacity (line 20 / 5)	439.0708		339.9207	
22	Production Expenses				
23	Operation Supervision and Engineering	153,321		191,217	
24	Water for Power	1,283		1,732	
25	Hydraulic Expenses	274		370	
26	Electric Expenses	0		0	
27	Misc Hydraulic Power Generation Expenses	337,137		453,439	
28	Rents	-729		-1,009	
29	Maintenance Supervision and Engineering	0		0	
30	Maintenance of Structures	9,904		14,823	
31	Maintenance of Reservoirs, Dams, and Waterways	6,908		24,507	
32	Maintenance of Electric Plant	53,699		35,846	
33	Maintenance of Misc Hydraulic Plant	18,385		24,819	
34	Total Production Expenses (total 23 thru 33)	580,182		745,744	
35	Expenses per net KWh	0.0061		0.0062	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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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. 1927 Plant Name: Clearwater No. 1 (d)	FERC Licensed Project No. 1927 Plant Name: Clearwater No. 2 (e)	FERC Licensed Project No. 2420 Plant Name: Cutler (f)	Line No.
Run-of-River	Run-of-River	Storage	1
Outdoor	Outdoor	Conventional	2
1953	1953	1927	3
1953	1953	1927	4
15.00	26.00	30.00	5
14	16	22	6
8,212	8,678	3,285	7
			8
18	31	29	9
18	31	29	10
1	1	3	11
37,424,000	45,315,000	44,317,000	12
			13
0	0	3,505,129	14
562,143	1,269,008	3,778,805	15
4,423,491	10,462,312	6,535,549	16
1,019,027	1,308,082	1,697,203	17
39,142	250,151	566,413	18
0	0	0	19
6,043,803	13,289,553	16,083,099	20
402.9202	511.1367	536.1033	21
			22
92,402	158,743	189,148	23
9,888	17,139	1,925	24
99,394	172,284	71,764	25
0	0	0	26
278,246	410,215	531,897	27
1,474	2,556	10,267	28
0	0	0	29
19,853	15,472	10,089	30
37,835	36,113	26,909	31
123,475	49,365	51,905	32
40,234	76,181	199,827	33
702,801	938,068	1,093,731	34
0.0188	0.0207	0.0247	35

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/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. 1927 Plant Name: Fish Creek (b)	FERC Licensed Project No. 20 Plant Name: Grace (c)		
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Storage		
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional		
3	Year Originally Constructed	1952	1908		
4	Year Last Unit was Installed	1952	1923		
5	Total installed cap (Gen name plate Rating in MW)	11.00	33.00		
6	Net Peak Demand on Plant-Megawatts (60 minutes)	10	30		
7	Plant Hours Connect to Load	4,791	7,232		
8	Net Plant Capability (in megawatts)				
9	(a) Under Most Favorable Oper Conditions	10	33		
10	(b) Under the Most Adverse Oper Conditions	10	33		
11	Average Number of Employees	1	4		
12	Net Generation, Exclusive of Plant Use - Kwh	35,712,000	76,033,000		
13	Cost of Plant				
14	Land and Land Rights	0	62,169		
15	Structures and Improvements	562,328	1,330,267		
16	Reservoirs, Dams, and Waterways	6,200,989	7,820,729		
17	Equipment Costs	1,213,586	3,918,628		
18	Roads, Railroads, and Bridges	400,007	65,826		
19	Asset Retirement Costs	0	0		
20	TOTAL cost (Total of 14 thru 19)	8,376,910	13,197,619		
21	Cost per KW of Installed Capacity (line 20 / 5)	761.5373	399.9278		
22	Production Expenses				
23	Operation Supervision and Engineering	68,442	88,748		
24	Water for Power	7,251	2,117		
25	Hydraulic Expenses	72,889	88,402		
26	Electric Expenses	0	0		
27	Misc Hydraulic Power Generation Expenses	216,574	1,325,153		
28	Rents	1,081	678		
29	Maintenance Supervision and Engineering	0	0		
30	Maintenance of Structures	18,704	32,282		
31	Maintenance of Reservoirs, Dams, and Waterways	33,487	74,960		
32	Maintenance of Electric Plant	52,222	112,817		
33	Maintenance of Misc Hydraulic Plant	34,707	125,538		
34	Total Production Expenses (total 23 thru 33)	505,357	1,850,695		
35	Expenses per net KWh	0.0142	0.0243		

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of <u>2007/Q4</u>
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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. 2082 Plant Name: <u>Iron Gate</u> (d)	FERC Licensed Project No. 2082 Plant Name: <u>JC Boyle</u> (e)	FERC Licensed Project No. 1927 Plant Name: <u>Lemolo No. 1</u> (f)	Line No.
Storage	Storage	Storage	1
Outdoor	Outdoor	Outdoor	2
1962	1958	1955	3
1962	1958	1955	4
18.00	97.98	31.99	5
18	83	31	6
8,648	6,919	8,590	7
			8
19	83	32	9
19	83	32	10
1	2	1	11
119,206,000	275,892,000	127,469,000	12
			13
341,706	26,277	0	14
3,927,836	2,325,892	750,905	15
12,440,215	14,497,614	9,583,097	16
2,223,662	14,966,044	5,844,214	17
1,076,116	883,023	475,419	18
0	0	0	19
20,009,535	32,698,850	16,653,635	20
1,111.6408	333.7298	520.5888	21
			22
167,899	446,417	195,327	23
1,155	6,287	21,088	24
247	1,343	211,975	25
0	0	0	26
345,635	711,486	527,841	27
-721	641	3,145	28
0	0	0	29
537,922	6,982	22,617	30
14,449	66,183	49,952	31
28,828	35,429	28,601	32
16,546	98,404	85,535	33
1,111,960	1,373,172	1,146,081	34
0.0093	0.0050	0.0090	35

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/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. 1927 Plant Name: Lemolo No. 2 (b)	FERC Licensed Project No. 935 Plant Name: Merwin (c)		
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Storage (Re-Reg)		
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional		
3	Year Originally Constructed	1956	1931		
4	Year Last Unit was Installed	1956	1958		
5	Total installed cap (Gen name plate Rating in MW)	33.00	136.00		
6	Net Peak Demand on Plant-Megawatts (60 minutes)	34	143		
7	Plant Hours Connect to Load	8,747	8,760		
8	Net Plant Capability (in megawatts)				
9	(a) Under Most Favorable Oper Conditions	34	151		
10	(b) Under the Most Adverse Oper Conditions	34	151		
11	Average Number of Employees	1	8		
12	Net Generation, Exclusive of Plant Use - Kwh	148,711,000	473,420,000		
13	Cost of Plant				
14	Land and Land Rights	0	1,086,128		
15	Structures and Improvements	1,071,057	28,097,831		
16	Reservoirs, Dams, and Waterways	17,735,463	9,701,286		
17	Equipment Costs	2,089,025	14,080,128		
18	Roads, Railroads, and Bridges	1,649,779	1,820,649		
19	Asset Retirement Costs	0	0		
20	TOTAL cost (Total of 14 thru 19)	22,545,324	54,786,022		
21	Cost per KW of Installed Capacity (line 20 / 5)	683.1916	402.8384		
22	Production Expenses				
23	Operation Supervision and Engineering	201,100	1,471,765		
24	Water for Power	21,754	11,946		
25	Hydraulic Expenses	218,668	772,355		
26	Electric Expenses	0	0		
27	Misc Hydraulic Power Generation Expenses	516,896	1,040,399		
28	Rents	3,244	14		
29	Maintenance Supervision and Engineering	0	0		
30	Maintenance of Structures	34,996	8,155		
31	Maintenance of Reservoirs, Dams, and Waterways	56,147	12,235		
32	Maintenance of Electric Plant	18,638	33,684		
33	Maintenance of Misc Hydraulic Plant	88,494	77,927		
34	Total Production Expenses (total 23 thru 33)	1,159,937	3,428,480		
35	Expenses per net KWh	0.0078	0.0072		

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)					
<p>1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)</p> <p>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.</p> <p>3. If net peak demand for 60 minutes is not available, give that which is available specifying period.</p> <p>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.</p>					
Line No.	Item (a)	FERC Licensed Project No. 1927 Plant Name: Slide Creek (b)	FERC Licensed Project No. 20 Plant Name: Soda (c)		
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Storage		
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional		
3	Year Originally Constructed	1951	1924		
4	Year Last Unit was Installed	1951	1924		
5	Total installed cap (Gen name plate Rating in MW)	18.00	14.00		
6	Net Peak Demand on Plant-Megawatts (60 minutes)	18	7		
7	Plant Hours Connect to Load	8,141	6,350		
8	Net Plant Capability (in megawatts)				
9	(a) Under Most Favorable Oper Conditions	18	15		
10	(b) Under the Most Adverse Oper Conditions	18	15		
11	Average Number of Employees	1	2		
12	Net Generation, Exclusive of Plant Use - Kwh	81,721,000	15,156,000		
13	Cost of Plant				
14	Land and Land Rights	0	512,946		
15	Structures and Improvements	1,665,828	585,652		
16	Reservoirs, Dams, and Waterways	5,583,139	5,006,225		
17	Equipment Costs	1,341,717	2,072,224		
18	Roads, Railroads, and Bridges	16,778	0		
19	Asset Retirement Costs	0	0		
20	TOTAL cost (Total of 14 thru 19)	8,607,462	8,177,047		
21	Cost per KW of Installed Capacity (line 20 / 5)	478.1923	584.0748		
22	Production Expenses				
23	Operation Supervision and Engineering	112,123	37,346		
24	Water for Power	17,094	898		
25	Hydraulic Expenses	119,273	37,504		
26	Electric Expenses	0	0		
27	Misc Hydraulic Power Generation Expenses	322,631	396,446		
28	Rents	1,769	87		
29	Maintenance Supervision and Engineering	0	0		
30	Maintenance of Structures	33,842	1,259		
31	Maintenance of Reservoirs, Dams, and Waterways	30,303	-4,395		
32	Maintenance of Electric Plant	73,178	26,440		
33	Maintenance of Misc Hydraulic Plant	48,885	43,334		
34	Total Production Expenses (total 23 thru 33)	759,098	538,919		
35	Expenses per net KWh	0.0093	0.0356		

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/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: Omsted (b)	FERC Licensed Project No. 0 Plant Name: (c)		
1	Kind of Plant (Run-of-River or Storage)	Run-of-River			
2	Plant Construction type (Conventional or Outdoor)	Conventional			
3	Year Originally Constructed	1904			
4	Year Last Unit was Installed	1922			
5	Total installed cap (Gen name plate Rating in MW)	10.30	0.00		
6	Net Peak Demand on Plant-Megawatts (60 minutes)	8	0		
7	Plant Hours Connect to Load	6,877	0		
8	Net Plant Capability (in megawatts)				
9	(a) Under Most Favorable Oper Conditions	10	0		
10	(b) Under the Most Adverse Oper Conditions	10	0		
11	Average Number of Employees	4	0		
12	Net Generation, Exclusive of Plant Use - Kwh	20,164,000	0		
13	Cost of Plant				
14	Land and Land Rights	0	0		
15	Structures and Improvements	267,100	0		
16	Reservoirs, Dams, and Waterways	529,217	0		
17	Equipment Costs	31,914	0		
18	Roads, Railroads, and Bridges	12,641	0		
19	Asset Retirement Costs	0	0		
20	TOTAL cost (Total of 14 thru 19)	840,872	0		
21	Cost per KW of Installed Capacity (line 20 / 5)	81.6381	0.0000		
22	Production Expenses				
23	Operation Supervision and Engineering	64,941	0		
24	Water for Power	661	0		
25	Hydraulic Expenses	24,639	0		
26	Electric Expenses	0	0		
27	Misc Hydraulic Power Generation Expenses	327,471	0		
28	Rents	-15	0		
29	Maintenance Supervision and Engineering	0	0		
30	Maintenance of Structures	345	0		
31	Maintenance of Reservoirs, Dams, and Waterways	3,172	0		
32	Maintenance of Electric Plant	67,436	0		
33	Maintenance of Misc Hydraulic Plant	69,665	0		
34	Total Production Expenses (total 23 thru 33)	558,315	0		
35	Expenses per net KWh	0.0277	0.0000		

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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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

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 406 Line No.: -1 Column: b

Copco No. 1

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 406 Line No.: -1 Column: c

Copco No. 2

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 406 Line No.: -1 Column: d

Clearwater No. 1

Costs reported for this plant do not include significant intangible costs due to relicensing and settlement, which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the North Umpqua River system for the following projects at December 31, 2007 was \$71.2 million: Lemolo 1, Lemolo 2, Clearwater 1, Clearwater 2, Toketee, Fish Creek, Soda Springs, Slide Creek and the North Umpqua Common Plant.

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 406 Line No.: -1 Column: e

Clearwater No. 2

Costs reported for this plant do not include significant intangible costs due to relicensing and settlement, which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the North Umpqua River system for the following projects at December 31, 2007 was \$71.2 million: Lemolo 1, Lemolo 2, Clearwater 1, Clearwater 2, Toketee, Fish Creek, Soda Springs, Slide Creek and the North Umpqua Common Plant.

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 406 Line No.: -1 Column: f

Cutler

Costs reported for this plant do not include significant intangible costs due to relicensing, which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing at December 31, 2007 was \$1.2 million.

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 406 Line No.: 1 Column: b

Copco No. 1

Pondage for peaking - storage, Upper Klamath Lake.

Schedule Page: 406 Line No.: 1 Column: c

Copco No. 2

Storage, Upper Klamath Lake.

Schedule Page: 406 Line No.: 1 Column: d

Clearwater No. 1

Forebay for peaking.

Schedule Page: 406 Line No.: 1 Column: e

Clearwater No. 2

Forebay for peaking.

Schedule Page: 406.1 Line No.: -1 Column: b

Fish Creek

Costs reported for this plant do not include significant intangible costs due to relicensing, and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the North Umpqua River system for the following projects at December 31, 2007 was \$71.2 million: Lemolo 1, Lemolo 2, Clearwater 1, Clearwater 2, Toketee, Fish Creek, Soda Springs, Slide Creek and the North Umpqua Common Plant.

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 406.1 Line No.: -1 Column: c

Grace

Costs reported for this plant do not include significant intangible costs due to relicensing, and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the Bear River system for the following projects at December 31, 2007 was \$15 million: Grace, Oneida and Soda.

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 406.1 Line No.: -1 Column: d

Iron Gate

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 406.1 Line No.: -1 Column: e

JC Boyle

All or some of the renewable energy attributes associated with upgrades to this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 406.1 Line No.: -1 Column: f

Lemolo No. 1

Costs reported for this plant do not include significant intangible costs due to relicensing, and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the North Umpqua River system for the following projects at December 31, 2007 was \$71.2 million: Lemolo 1, Lemolo 2, Clearwater 1, Clearwater 2, Toketee, Fish Creek, Soda Springs, Slide Creek and the North Umpqua Common Plant.

All or some of the renewable energy attributes associated with upgrades to this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 406.1 Line No.: 1 Column: b

Fish Creek

Forebay for peaking.

Schedule Page: 406.1 Line No.: 1 Column: d

Iron Gate

Storage for regulation.

Schedule Page: 406.1 Line No.: 1 Column: e

JC Boyle

Pondage for peaking - storage, Upper Klamath Lake.

Schedule Page: 406.1 Line No.: 1 Column: f

Lemolo No. 1

Storage, Lemolo Lake.

Schedule Page: 406.2 Line No.: -1 Column: b

Lemolo No. 2

Costs reported for this plant do not include significant intangible costs due to relicensing, and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the North Umpqua River system for the following projects at December 31, 2007 was \$71.2 million: Lemolo 1, Lemolo 2, Clearwater 1, Clearwater 2, Toketee, Fish Creek, Soda Springs, Slide Creek and the North Umpqua Common Plant.

Schedule Page: 406.2 Line No.: -1 Column: c

Merwin

Costs reported for this plant do not include significant intangible costs due to relicensing, and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the Lewis River system for the following projects at December 31, 2007 was \$429 thousand : Merwin, Yale, and Swift #1.

Schedule Page: 406.2 Line No.: -1 Column: d

Toketee

Costs reported for this plant do not include significant intangible costs due to relicensing, and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the North Umpqua River system for the following projects at December 31, 2007 was \$71.2 million: Lemolo 1, Lemolo 2, Clearwater 1,

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Clearwater 2, Toketee, Fish Creek, Soda Springs, Slide Creek and the North Umpqua Common Plant.

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 406.2 Line No.: -1 Column: e

Oneida

Costs reported for this plant do not include significant intangible costs due to relicensing, and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the Bear River system for the following projects at December 31, 2007 was \$15 million: Grace, Oneida and Soda.

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 406.2 Line No.: -1 Column: f

Prospect No. 2

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 406.2 Line No.: 1 Column: b

Lemolo No. 2

Storage, Lemolo Lake.

Schedule Page: 406.2 Line No.: 1 Column: d

Toketee

Pondage for peaking - storage, Lemolo Lake.

Schedule Page: 406.2 Line No.: 1 Column: f

Prospect No. 2

Forebay for peaking.

Schedule Page: 406.3 Line No.: -1 Column: b

Slide Creek

Costs reported for this plant do not include significant intangible costs due to relicensing, and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the North Umpqua River system for the following projects at December 31, 2007 was \$71.2 million: Lemolo 1, Lemolo 2, Clearwater 1, Clearwater 2, Toketee, Fish Creek, Soda Springs, Slide Creek and the North Umpqua Common Plant.

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 406.3 Line No.: -1 Column: c

Soda

Costs reported for this plant do not include significant intangible costs due to relicensing, and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the Bear River system for the following projects at December 31, 2007 was \$15 million: Grace, Oneida and Soda.

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 406.3 Line No.: -1 Column: d

Soda Springs

Costs reported for this plant do not include significant intangible costs due to relicensing, and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the North Umpqua River system for the following projects at December 31, 2007 was \$71.2 million: Lemolo 1, Lemolo 2, Clearwater 1, Clearwater 2, Toketee, Fish Creek, Soda Springs, Slide Creek and the North Umpqua Common Plant.

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 406.3 Line No.: -1 Column: e

Swift #1

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Costs reported for this plant do not include significant intangible costs due to relicensing, and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the Lewis River system for the following projects at December 31, 2007 was \$429 thousand : Merwin, Yale, and Swift #1.

Schedule Page: 406.3 Line No.: -1 Column: f

Yale

Costs reported for this plant do not include significant intangible costs due to relicensing, and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the Lewis River system for the following projects at December 31, 2007 was \$429 thousand : Merwin, Yale, and Swift #1.

Schedule Page: 406.4 Line No.: -1 Column: b

Olmstead

The Olmstead Plant is owned by the U.S. Bureau of Land Reclamation. PacifiCorp has a 25-year lease beginning in 1990. The respondent operates the plant and owns the generation.

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GENERATING PLANT STATISTICS (Small Plants)						
1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.						
Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Hydro Licensed Proj. No.					
2	American Fork 696	1907	0.95			
3	Ashton 2381	1917	6.85	6.3	30,914	8,788,512
4	Upper Beaver 814	1907	2.52	1.2	7,151	
5	Bend	1913	1.11	1.0	2,863	896,299
6	Big Fork 2652	1910	4.15	4.6	24,435	6,642,937
7	Cline Falls	1913	1.00	1.1		302,594
8	Condit 2342	1913	13.70	15.0	84,395	6,924,313
9	Eagle Point	1957	2.81	2.8	18,520	1,791,404
10	Eastside 2082	1924	3.20	3.0	10,528	1,896,121
11	Fall Creek 2082	1903	2.20	2.0	13,049	1,088,570
12	Fountain Green	1922	0.16	0.2	624	451,779
13	Granite	1896	2.00	0.8	1,796	4,896,073
14	Gunlock	1917	0.75	0.3	776	596,348
15	Last Chance	1983	1.73	1.4	3,006	2,715,132
16	Paris	1910	0.72	0.6	1,905	313,213
17	Pioneer 2722	1897	5.00	4.0	12,263	9,818,038
18	Prospect No. 1 2630	1912	3.76	3.8	14,729	953,772
19	Prospect No. 3 2337	1932	7.20	7.2	44,199	6,930,313
20	Prospect No. 4 2630	1944	1.00	0.9	2,024	371,469
21	Sand Cove	1926	0.80	0.2	707	860,056
22	Snake Creek	1910	1.18	0.5	2,837	904,669
23	Stairs 587	1895	1.00	1.1	4,139	1,179,463
24	St. Anthony 2381	1915	0.50			1,337,279
25	Veyo	1920	0.50	0.2	717	727,360
26	Viva Naughton	1986	0.74	0.6	651	1,169,596
27	Wallowa Falls 308	1921	1.10	1.0	6,162	2,770,134
28	Weber 1744	1911	3.85	2.0	16,483	2,728,814
29	West Side 2082	1908	0.60	0.6	371	354,926
30	Keno Regulating Dam 2082					7,475,589
31	Upper Klamath Lake 2082					4,979,168
32	North Umpqua 1927					13,381,109
33						
34	Pumping Plant:					
35	Lifton	1917	-4.50	-3.0	-4,963	16,501,074
36						
37	Wind Turbine:					
38	Foot Creek	1998	32.62	32.6	95,139	36,966,153
39	Leaning Juniper #1	2006	100.50	100.0	289,452	172,384,705
40	Marengo	2007	140.40	138.0	160,636	238,779,233
41						
42						
43						
44						
45						
46						

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GENERATING PLANT STATISTICS (Small Plants) (Continued)						
3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.						
Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
	18,999		6,112	Water		2
1,282,994	398,222		83,598	Water		3
	138,148		5,927	Water		4
807,477	122,635		8,088	Water		5
1,600,708	192,800		286,279	Water		6
302,594	4,752		941	Water		7
505,424	275,987		86,177	Water		8
637,510	212,962		72,156	Water		9
592,538	69,664		25,423	Water		10
494,805	73,424		59,126	Water		11
2,823,619	23,754		15,778	Water		12
2,448,037	115,141		15,065	Water		13
795,131	75,108		42,443	Water		14
1,569,440	137,598		37,589	Water		15
435,018	48,784		23,003	Water		16
1,963,608	245,434		167,440	Water		17
253,663	106,328		26,902	Water		18
962,543	263,217		91,813	Water		19
371,469	33,463		10,527	Water		20
1,075,070	75,660		52,594	Water		21
766,669	87,825		17,775	Water		22
1,179,463	104,262		34,894	Water		23
2,674,558	31,146		2,492	Water		24
1,454,720	105,866		26,866	Water		25
1,580,535	34,349		12,159	Water		26
2,518,304	44,283		58,165	Water		27
708,783	212,027		78,142	Water		28
591,543	21,290		17,552	Water		29
	2,569		13,533			30
	-872,830		39,970			31
						32
						33
						34
-3,666,905	236,218		35,871	Water.		35
						36
						37
1,133,236	1,487,206			Wind		38
1,715,271	3,386,951			Wind		39
1,700,707	1,879,278			Wind		40
						41
						42
						43
						44
						45
						46

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Schedule Page: 410 Line No.: 1 Column: a

Common river system costs for the operation of these facilities are allocated to each plant based upon the unit's name plate rating.

Schedule Page: 410 Line No.: 2 Column: a

American Fork

In August 2004, the FERC authorized the removal of the 1-MW (nameplate rating) American Fork hydroelectric plant and facilities. Decommissioning of the American Fork facilities has been completed in accordance with the approved removal plan. The removal of the dam, flowline and all facilities, with the exception of the powerhouse that has been designated a historical landmark, was completed in December 2007. As of December 31, 2007, \$4 million had been spent for the decommissioning of the American Fork hydroelectric project.

Schedule Page: 410 Line No.: 3 Column: a

Ashton

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Costs reported for this plant do not include significant intangible costs due to relicensing which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing at December 31, 2007 was \$375,259.

Schedule Page: 410 Line No.: 4 Column: a

Upper Beaver

On September 14, 2007, PacifiCorp closed the sale of the Upper Beaver Hydroelectric Project, Federal Energy Regulatory Commission ("FERC") Project No. 814, assets and water rights, to the City of Beaver, Utah, for \$2 million. In accordance with 18 CFR Part 4.94 (f) Article 6, notification of the transfer of the license exemption was filed with the FERC. The Upper Beaver Hydroelectric Project is located in southwestern Utah, on the Beaver River near the City of Beaver, upon United States Forest Service ("USFS") lands in the Fish Lake National Forest, and operated under the authority of a special use permit with the USFS. The proceeds, net book value, and selling costs were transferred to account 102, Electric plant purchased or sold. In March 2008, PacifiCorp filed with the FERC the journal entries called for by the Uniform System of Accounts. The sale was approved by the Wyoming, Oregon and California state commissions.

Schedule Page: 410 Line No.: 5 Column: a

Bend

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Costs reported for this plant do not include significant intangible costs due to relicensing which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing at December 31, 2007 was \$281,224.

Schedule Page: 410 Line No.: 6 Column: a

Big Fork

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Costs reported for this plant do not include significant intangible costs due to relicensing which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing at December 31, 2007 was \$573,106.

Schedule Page: 410 Line No.: 7 Column: a

Cline Falls

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 410 Line No.: 8 Column: a

Condit

In September 1999, a settlement agreement to remove the 10-MW (nameplate rating) Condit hydroelectric project was signed by PacifiCorp, state and federal agencies and non-governmental organizations. Under the original settlement agreement, removal was expected to begin in October 2006, with a total cost to decommission not to exceed \$17 million, excluding inflation. In early February 2005, the parties agreed to modify the settlement agreement so that removal will not begin until October 2008 for a total cost to decommission not to exceed \$21 million, excluding inflation. The settlement agreement is contingent upon receiving a FERC surrender order and other regulatory approvals that are not materially inconsistent with the amended settlement agreement. PacifiCorp

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is in the process of acquiring all necessary permits, within the terms and conditions of the amended settlement agreement. If the permitting process continues into the second quarter of 2008, the decommissioning will not begin until October 2009.

Costs reported for this plant do not include significant intangible costs due to relicensing which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing at December 31, 2007 was \$120,264.

Schedule Page: 410 Line No.: 9 Column: a

Eagle Point

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 410 Line No.: 10 Column: a

Eastside

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

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

Fall Creek

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 410 Line No.: 12 Column: a

Fountain Green

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Costs reported for this plant do not include significant intangible costs due to relicensing which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing at December 31, 2007 was \$8,608.

Schedule Page: 410 Line No.: 13 Column: a

Granite

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 410 Line No.: 14 Column: a

Gunlock

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Costs reported for this plant do not include significant intangible costs due to relicensing which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing at December 31, 2007 was \$52,775.

Schedule Page: 410 Line No.: 15 Column: a

Last Chance

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 410 Line No.: 16 Column: a

Paris

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 410 Line No.: 17 Column: a

Pioneer

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Costs reported for this plant do not include significant intangible costs due to relicensing which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing at December 31, 2007 was \$125,995.

Schedule Page: 410 Line No.: 18 Column: a

Prospect 1

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or

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federal renewable portfolio standards.

Schedule Page: 410 Line No.: 19 Column: a

Prospect 3

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Costs reported for this plant do not include significant intangible costs due to relicensing which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing at Prospect unit number 3 on December 31, 2007 was \$107,837.

Schedule Page: 410 Line No.: 20 Column: a

Prospect 4

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 410 Line No.: 21 Column: a

Sand Cove

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 410 Line No.: 22 Column: a

Snake Creek

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 410 Line No.: 23 Column: a

Stairs

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Costs reported for this plant do not include significant intangible costs due to relicensing which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing at December 31, 2007 was \$98,935.

Schedule Page: 410 Line No.: 24 Column: a

St. Anthony

Licensed Project No. 2381 applicable to both Ashton and St. Anthony plants.

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 410 Line No.: 25 Column: a

Veyo

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 410 Line No.: 26 Column: a

Viva Naughton

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 410 Line No.: 27 Column: a

Wallowa Falls

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 410 Line No.: 28 Column: a

Weber

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Costs reported for this plant do not include significant intangible costs due to relicensing which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing at December 31, 2007 was \$383,296.

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Schedule Page: 410 Line No.: 29 Column: a

West Side

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 410 Line No.: 30 Column: a

Keno Regulating Dam

Used in regulating the release of water from Klamath Lake and in maintaining proper water surface level in the Klamath River between Klamath Falls and Keno, Oregon.

Schedule Page: 410 Line No.: 31 Column: a

Upper Klamath Lake

Storage reservoir for six plants on the Klamath River (Copco No. 1, Copco No. 2, East Side, West Side, John C. Boyle, and Iron Gate).

Schedule Page: 410 Line No.: 32 Column: a

North Umpqua

Common plant in North Umpqua Project. All common roads, employee houses, control equipment, etc. are in this account.

Costs reported for this plant do not include significant intangible costs due to relicensing and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the North Umpqua River system for the following projects at December 31, 2007 was \$71.2 million: Lemolo 1, Lemolo 2, Clearwater 1, Clearwater 2, Toketee, Fish Creek, Soda Springs, Slide Creek and the North Umpqua Common Plant.

Schedule Page: 410 Line No.: 38 Column: a

Foot Creek

The Foot Creek Wind Farm is operated by SeaWest Energy and is jointly owned. Costs reported for this plant represents the respondents share. Ownership of the plant is as follows: PacifiCorp 78.79%, Eugene Water and Electric Board 21.21%.

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

Schedule Page: 410 Line No.: 39 Column: a

Leaning Juniper #1

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

The cost of plant balance includes \$478,678 of asset retirement costs.

Schedule Page: 410 Line No.: 40 Column: a

Marengo

All or some of the renewable energy attributes associated with this generation may be used in future years to comply with state or federal renewable portfolio standards.

The cost of plant balance includes \$475,680 of asset retirement costs.

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TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Malin, OR	Indian Springs, CA	500.00	500.00	Steel Tower	47.00		1
2	Midpoint, ID	Malin, OR	500.00	500.00	Steel Tower	446.00		1
3	Malin, OR	Medford, OR	500.00	500.00	Steel Tower	84.00		1
4	Alvey Sub, OR	Dixonville Sub, OR	500.00	500.00	Steel Tower		58.00	1
5	Malin, OR	Captain Jack, OR	500.00	500.00	Steel Tower	7.00		1
6	Dixonville, OR	Meridian, OR	500.00	500.00	Steel Tower		74.00	1
7	Colstrip 4, MT	Switchyard, MT	500.00	500.00	Steel Tower		1.00	1
8	Colstrip, MT	Broadview A, MT	500.00	500.00	Steel Tower		112.00	1
9	Colstrip, MT	Broadview B, MT	500.00	500.00	Steel Tower		116.00	1
10	Broadview, MT	Townsend A, MT	500.00	500.00	Steel Tower		133.00	1
11	Broadview, MT	Townsend B, MT	500.00	500.00	Steel Tower		133.00	1
12	500 kV expenses							
13								
14	Subtotal 500 kV					584.00	627.00	11
15								
16	Ben Lomond Sub., UT	Borah Substation, ID	345.00	345.00	Steel - H	133.00		1
17	Ben Lomond Sub., UT	Terminal Substation, UT	345.00	345.00	Steel - D	47.00		2
18	Spanish Fork Sub., UT	Camp Williams Sub., UT	345.00	345.00	Steel - SP	35.00		2
19	Huntington Plant, UT	Sigurd Substation, UT	345.00	345.00	Steel - H	95.00		1
20	Huntington Plt. Sub., UT	Spanish Fork Sub., UT	345.00	345.00	Steel - H	78.00		1
21	Terminal Substation, UT	Ninety South Sub., UT	345.00	345.00	Steel - SP	16.00		2
22	Emery Substation, UT	Sigurd Substation, UT	345.00	345.00	Steel - H	75.00		1
23	Sigurd Substation, UT	Camp Williams Sub., UT	345.00	345.00	Steel - H-P	116.00		1
24	Camp Williams Sub., UT	Ninety South Sub., UT	345.00	345.00	Steel - SP	11.00		2
25	Terminal Substation, UT	Camp Williams Sub., UT	345.00	345.00	Steel - D	26.00		1
26	Emery Substation, UT	Camp Williams Sub., UT	345.00	345.00	Steel - H	121.00		1
27	Newcastle, UT	Utah - Nevada Border	345.00	345.00	Steel - D	54.00		1
28	Sigurd Substation, UT	Newcastle, UT	345.00	345.00	Steel - D	137.00		1
29	Goshen Substation, ID	Kinport Substation, ID	345.00	345.00	Steel - H	41.00		1
30	Huntington Plant, UT	Four Corners Sub., NM	345.00	345.00	Wood - U	101.00		1
31	Camp Williams Sub., UT	Huntington Plant, UT	345.00	345.00	Wood - U	107.00		1
32	Huntington Plant, UT	Pinto Substation, UT	345.00	345.00	Wood - U	160.00		1
33	Camp Williams Sub., UT	Sigurd Substation, UT	345.00	345.00	Wood - U	70.00		1
34	Jim Bridger Plant #3, WY	Borah Substation, ID	345.00	345.00	Steel Tower	240.00		1
35	Jim Bridger Plant #2, WY	Kinport Substation, ID	345.00	345.00	Steel Tower	234.00		1
36					TOTAL	15,494.00	777.00	210

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2-1852	134,356	5,551,720	5,686,076					1
1272.0	3,086,400	151,381,956	154,468,356					2
1272.0	2,907,175	38,015,889	40,923,064					3
1272.0	1,468,204	19,597,617	21,065,821					4
1272.0	9,230	1,460,042	1,469,272					5
1272.0	4,769,435	26,255,866	31,025,301					6
795 KCM ACSR		25,657	25,657					7
795 KCM ACSR	218,759	5,413,613	5,632,372					8
795 KCM ACSR	276,825	7,158,284	7,435,109					9
795 KCM ACSR	418,613	6,568,174	6,986,787					10
795 KCM ACSR	436,168	6,491,204	6,927,372					11
				16,507	853,926	99,199	*****	12
								13
	13,725,165	267,920,022	281,645,187	16,507	853,926	99,199	*****	14
								15
954.0	5,229,653	35,321,732	40,551,385					16
1272.0	9,369,708	22,112,724	31,482,432					17
1272.0	5,508,409	10,158,595	15,667,004					18
954.0	343,174	20,080,785	20,423,959					19
954.0	855,936	17,683,269	18,539,205					20
1272.0	2,557,855	7,457,557	10,015,412					21
954.0	320,316	13,619,157	13,939,473					22
954.0	510,490	25,192,646	25,703,136					23
1272.0	482,866	3,895,713	4,378,579					24
1272.0	4,301,937	7,970,335	12,272,272					25
954.0	926,251	27,921,108	28,847,359					26
954.0	2,320,872	50,682,835	53,003,707					27
954.0	56,050	13,605,651	13,661,701					28
795.0	313,477	2,571,824	2,885,301					29
954.0	117,662	2,893,802	3,011,464					30
795.0	893,965	19,882,390	20,776,355					31
795.0								32
795.0	179,502	16,211,906	16,391,408					33
1272.0	1,128,222	26,302,241	27,430,463					34
1272.0	1,099,796	28,083,728	29,183,524					35
	85,897,343	1,695,585,078	1,781,482,421	125,807	13,323,841	1,316,314	14,765,962	36

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Currant Creek Swtchrd, UT	Mona Substation, UT	345.00	345.00	Steel - SP	1.00		
2	Camp Williams Sub, UT	Mona Sub, UT	345.00	345.00	Wood - SP	8.00	42.00	1
3	345 kV expenses							
4								
5	Subtotal 345 kV					1,906.00	42.00	25
6								
7	Fairview, OR	Isthmus, OR	230.00	230.00	H Frame Wood	12.00		1
8	Antelope Sub., ID	Lost River 230kV Line, ID	230.00	230.00	Wood - H	20.00		1
9	Walla Walla, WA	Hells Canyon, ID	230.00	230.00	H Frame Wood	78.00		1
10	Bethel, OR	Fry, OR	230.00	230.00	H Frame Wood	26.00		1
11	Fry, OR	Dixonville, OR	230.00	230.00	H Frame Wood	45.00		1
12	Alvey, OR	Dixonville, OR	230.00	230.00	H Frame Wood	59.00		1
13	Troutdale, OR	Linneman, OR	230.00	230.00	Steel Tower	6.00		1
14	Troutdale, OR	Gresham, OR	230.00	230.00	Steel Tower	6.00		1
15	McNary, WA	Walla Walla, WA	230.00	230.00	H Frame Wood	56.00		1
16	BPA Heppner, OR	Dalred Substation, OR	230.00	230.00	H Frame Wood	1.00		1
17	Sigurd Substation, UT	Garfield, UT	230.00	230.00	Wood - U	117.00		1
18	Dixonville, OR	Reston, OR	230.00	230.00	H Frame Wood	17.00		1
19	Yamsey, OR	Klamath Falls, OR	230.00	230.00	H Frame Wood	56.00		1
20	Yamsey, OR	Klamath Falls, OR	230.00	230.00	Steel Tower	6.00		1
21	Dixonville, OR	Lone Pine, OR	230.00	230.00	H Frame Wood	8.00		1
22	Klamath Falls, OR	Medford, OR	230.00	230.00	H Frame Wood	76.00		1
23	Klamath Falls, OR	Malin, OR	230.00	230.00	H Frame Wood	35.00		1
24	Table Rock, SW Station, OR	Grants Pass, OR	230.00	230.00	H Frame Wood	35.00		1
25	Grants Pass, OR	Days Creek, OR	230.00	230.00	H Frame Wood	71.00		1
26	Dixonville, OR	Dixonville, OR	230.00	230.00	Wood	1.00		
27	Sigurd Substation, UT	Pavant Substation, UT	230.00	230.00	Wood - U	43.00		1
28	Pavant Substation, UT	Nevada - Utah State line	230.00	230.00	Wood - U	98.00		1
29	Bannock Pass, ID	Antelope Sub., ID	230.00	230.00	Wood - U	76.00		1
30	Brady Substation, ID	Treasureton Sub., ID	230.00	230.00	Wood - U	66.00		1
31	Ben Lomond Sub., UT	Naughton Plt. #1, WY	230.00	230.00	Wood - U	88.00		1
32	Sigurd Substation, UT	Arizona - Utah State line	230.00	230.00	Wood - U	149.00		1
33	Birch Creek Sub., WY	Railroad Substation, WY	230.00	230.00	Wood - HSW	12.00		1
34	Birch Creek Sub., WY	Railroad Substation, WY	230.00	230.00	Wood - HSW	7.00		1
35	Ben Lomond Sub., UT	Naughton Plt. #2, WY	230.00	230.00	Wood - U	59.00		1
36					TOTAL	15,494.00	777.00	210

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TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
		1,178,479	1,178,479					1
1272		9,578,059	9,578,059					2
					1,160,237	246,299	*****	3
								4
	36,516,141	362,404,536	398,920,677		1,160,237	246,299	*****	5
								6
954.0	285,322	1,702,523	1,987,845					7
795.0	12,929	1,200,282	1,213,211					8
1272.0	64,394	11,244,114	11,308,508					9
1272.0	351,982	1,908,416	2,260,398					10
1272.0	485,896	4,968,451	5,454,347					11
954.0	1,428,247	14,703,211	16,131,458					12
954.0		423,036	423,036					13
954.0	363,717	574,074	937,791					14
1272.0	220,967	3,403,514	3,624,481					15
795.0		108,025	108,025					16
795.0	468,992	7,660,343	8,129,335					17
	39,971	1,558,343	1,598,314					18
795.0								19
795.0	473,366	4,453,059	4,926,425					20
795.0	439,563	4,128,249	4,567,812					21
795.0	173,608	6,065,263	6,238,871					22
1272.0	115,448	1,798,928	1,914,376					23
954.0	191,124	5,203,472	5,394,596					24
1272.0	379,961	11,874,572	12,254,533					25
1272.0		508,736	508,736					26
795.0	41,499	4,372,038	4,413,537					27
795.0								28
1272.0	5,103	2,481,761	2,486,864					29
795.0	72,118	2,165,408	2,237,526					30
795.0	426,126	4,570,641	4,996,767					31
954.0	22,643	4,584,254	4,606,897					32
954.0	165,054	1,299,642	1,464,696					33
954.0	181,047	1,520,220	1,701,267					34
1272.0	736,030	5,273,727	6,009,757					35
	85,897,343	1,695,585,078	1,781,482,421	125,807	13,323,841	1,316,314	14,765,962	36

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Ben Lomond Sub., UT	Naughton Plt. #2, WY	230.00	230.00	Wood - U	29.00		1
2	Chappel Creek, WY	Naughton Plant, WY	230.00	230.00	Wood Tower	46.00		1
3	Ben Lomond Sub., UT	Terminal Substation, UT	230.00	230.00	Steel - D-P	76.00		1
4	Naughton Plant, WY	Treasureton Sub., ID	230.00	230.00	Wood - U	79.00		1
5	Naughton Plant, WY	Treasureton Sub., ID	230.00	230.00	Wood - U	1.00		1
6	Swift Plant #1, WA	Cowlitz Co. Line, WA	230.00	230.00	H Frame Wood	3.00		1
7	Swift Plant #2, WA	BPA Woodland, WA	230.00	230.00	H Frame Wood	23.00		1
8	Union Gap, WA	BPA Midway, WA	230.00	230.00	H Frame Wood	39.00		1
9	Walla Walla, WA	Lewiston, ID	230.00	230.00	H Frame Wood	45.00		1
10	Walla Walla, WA	Wanapum, WA	230.00	230.00	H Frame Wood	33.00		1
11	Pomona, WA	Wanapum, WA	230.00	230.00	H Frame Wood	37.00		1
12	Pomona, WA	Wanapum, WA	230.00	230.00	H Frame Wood	8.00		1
13	Meridian Sub, OR	Lone Pine Sub, OR	230.00	230.00	Steel - DC	5.00		
14	Meridian Sub, OR	Lone Pine Sub, OR	230.00	230.00	Steel - DC		5.00	
15	Goose Creek, WY	Yellowtail, MT	230.00	230.00	H Frame Wood	59.00		1
16	Yellowtail, MT	Muddy Ridge, WY	230.00	230.00	H Frame Wood	176.00		1
17	Sheridan, WY	Decker, MT	230.00	230.00	H Frame Wood	12.00		1
18	Dave Johnston Plant, WY	Casper, WY	230.00	230.00	H Frame Wood	31.00		1
19	Yellowtail, MT	Casper, WY	230.00	230.00	H Frame Wood	149.00		1
20	Rock Springs, WY	Kemmerer, WY	230.00	230.00	H Frame Wood	71.00		1
21	Rock Springs, WY	Atlantic City, WY	230.00	230.00	H Frame Wood	69.00		1
22	Thermopolis, WY	Riverton, WY	230.00	230.00	H Frame Wood	51.00		1
23	Casper, WY	Riverton, WY	230.00	230.00	H Frame Wood	110.00		1
24	Dave Johnston Plant, WY	Rock Springs, WY	230.00	230.00	H Frame Wood	209.00		1
25	Dave Johnston Plant, WY	Spence, WY	230.00	230.00	H Frame Wood	31.00		1
26	Riverton, WY	Atlantic City, WY	230.00	230.00	H Frame Wood	50.00		1
27	Rock Springs, WY	Flaming Gorge, UT	230.00	230.00	H Frame Wood	48.00		1
28	Palisades, WY	Green River, WY	230.00	230.00	H Frame Wood	5.00		1
29	Buffalo, WY	Gillette, WY	230.00	230.00	H Frame Wood	69.00		1
30	Jim Bridger Plant, WY	Point of Rocks, WY	230.00	230.00	H Frame Wood	4.00		1
31	Jim Bridger Plant, WY	Point of Rocks, WY	230.00	230.00	H Frame Wood	5.00		
32	Dave Johnston Plant, WY	Yellowcake, WY	230.00	230.00	H Frame Wood	69.00		1
33	Wyodak, WY	Sub. Tie Line, WY	230.00	230.00	H Frame Wood	1.00		1
34	Jim Bridger Plant, WY	Point of Rocks Ln 2, WY	230.00	230.00	H Frame Wood	8.00		1
35	Blue Rim, WY	South Trona, WY	230.00	230.00	H Frame Wood	13.00		1
36					TOTAL	15,494.00	777.00	210

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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TRANSMISSION LINE STATISTICS (Continued)

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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.
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272.0		1,721,522	1,721,522					1
954.0	170,967	5,900,151	6,071,118					2
1272.0	572,459	10,217,612	10,790,071					3
954.0	56,498	3,070,270	3,126,768					4
954.0	569	27,377	27,946					5
954.0	1,293	335,329	336,622					6
954.0	103,532	2,598,048	2,701,580					7
1272.0	172,451	1,709,377	1,881,828					8
1272.0	366,290	6,331,575	6,697,865					9
954.0	235,532	2,389,938	2,625,470					10
1780.0	207,123	2,664,144	2,871,267					11
556.5	169	1,514,180	1,514,349					12
1272		2,003,740	2,003,740					13
								14
1272.0	1,714,529	2,100,252	3,814,781					15
1272.0	1,615,025	5,951,730	7,566,755					16
1272.0	26,093	630,118	656,211					17
795.0	14,928	1,147,317	1,162,245					18
1271.0	130,197	9,689,026	9,819,223					19
1271.0	52,906	3,439,244	3,492,150					20
954.0	31,859	3,001,623	3,033,482					21
1272.0	57,112	2,100,040	2,157,152					22
954.0	67,857	5,083,127	5,150,984					23
1272.0	58,102	11,533,953	11,592,055					24
1272.0	33,008	2,658,645	2,691,653					25
1271.0	48,281	3,806,177	3,854,458					26
1272.0	30,769	2,662,969	2,693,738					27
1272.0	12	697,350	697,362					28
1272.0	361,351	4,344,620	4,705,971					29
1272.0	4,800	140,312	145,112					30
1272.0		130,166	130,166					31
1272.0	294,290	6,158,106	6,452,396					32
1272.0		15,274	15,274					33
1272.0	3,967	441,494	445,461					34
1272.0		872,981	872,981					35
	85,897,343	1,695,585,078	1,781,482,421	125,807	13,323,841	1,316,314	14,765,962	36

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Monument, WY	Exxon Plant, WY	230.00	230.00	H Frame Wood	13.00		1
2	Firehole, WY	Mansface, WY	230.00	230.00	Steel Pole	2.00		1
3	Firehole, WY	Mansface, WY	230.00	230.00	H Frame Wood	10.00		1
4	Monuments, WY	South Trona, WY	230.00	230.00	H Frame Wood	4.00		1
5	Spence Sub., WY	Jim Bridger Plant, WY	230.00	230.00	H Frame Wood	47.00		
6	Jim Bridger Plant, WY	Mustang Sub., WY	230.00	230.00	H Frame Wood	73.00		1
7	Spence Sub., WY	Mustang Sub., WY	230.00	230.00	H Frame Wood	77.00		1
8	Rock Springs, WY	Flaming Gorge, UT	230.00	230.00	Steel Tower	7.00		1
9	Line 59, CA	Copco II, CA	230.00	230.00	H Frame Wood	5.00		1
10	Arizona/Utah State Line	Glen Canyon Sub., AZ	230.00	230.00	H Frame Wood	10.00		1
11	Miners Sub., WY	Foote Creek Sub., WY	230.00	230.00	Wood - H	29.00		1
12	Monument Sub., WY	Craven Creek Sub., WY	230.00	230.00	Wood - H	20.00		1
13	Point of Rocks Sub., WY	Rock Springs, WY	230.00	230.00	Wood - H	27.00		1
14	230 kV expenses							
15								
16	Subtotal 230 kV					3,317.00	5.00	72
17								
18	Montana-Idaho State line	Grace Plant, ID	161.00	161.00	Wood - H	57.00	90.00	1
19	Goshen Substation, ID	Rigby Substation, ID	161.00	161.00	Wood - H	61.00		1
20	Goshen Substation, ID	Antelope Substation, ID	161.00	161.00	Wood - H	45.00		1
21	Goshen Substation, ID	Sugar Mill Substation, ID	161.00	161.00	Wood - SP	17.00		1
22	Sugar Mill Sub., ID	Rigby Substation, ID	161.00	161.00	Wood - SP	17.00		1
23	Goshen Substation, ID	Bonneville Sub., ID	161.00	161.00	Wood - SP-H	23.00		1
24	Billings, MT	Yellowtail, MT	161.00	161.00	H Frame Wood	46.00		1
25	Big Grassy Sub., ID	Idaho Power Line, ID	161.00	161.00	Wood - H	1.00		1
26	Rigby Sub., ID	Jefferson Roberts, ID	161.00	161.00	Wood - SP	18.00		1
27	Thermopolis Sub, WY	Wapa Tie Line, WY	161.00					
28	161 kV expenses							
29								
30	Subtotal 161 kV					285.00	90.00	9
31								
32	Naughton Plant, WY	Evanston Substation, WY	138.00	138.00	Wood - H	67.00		1
33	Evanston Substation, WY	Anschutz Substation, WY	138.00	138.00	Wood - H	6.00		1
34	Evanston Substation, WY	Anschutz Substation, WY	138.00	138.00	Wood - H	15.00		1
35	Naughton Plant, WY	Carter Creek Sub., WY	138.00	138.00	Wood - H	36.00		1
36					TOTAL	15,494.00	777.00	210

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272.0		160,129	160,129					1
1272.0								2
1272.0		2,674,008	2,674,008					3
1272.0		2,726,304	2,726,304					4
1272.0		170,295	170,295					5
1272.0		9,760,523	9,760,523					6
1272.0		9,565,742	9,565,742					7
1272.0	4,482	744,631	749,113					8
	4,339	820,071	824,410					9
	11,901	451,363	463,264					10
		4,972,560	4,972,560					11
		4,548,527	4,548,527					12
		5,939,085	5,939,085					13
				31,548	2,896,603	396,993	*****	14
								15
	13,597,798	259,375,327	272,973,125	31,548	2,896,603	396,993	*****	16
								17
397.5	18,978	1,585,831	1,604,809					18
397.5	27,520	808,384	835,904					19
397.5	8,857	2,667,758	2,676,615					20
397.5	48,227	1,482,266	1,530,493					21
397.5	27,536	1,210,177	1,237,713					22
954.0	362,279	2,835,396	3,197,675					23
556.5	1,523,642	1,830,017	3,353,659					24
556.5		26,208	26,208					25
556.5	76,306	1,284,658	1,360,964					26
		12,306	12,306					27
				41,929	251,180	4,540	*****	28
								29
	2,093,345	13,743,001	15,836,346	41,929	251,180	4,540	*****	30
								31
795.0	146,645	4,036,209	4,182,854					32
795.0	129,129	504,914	634,043					33
795.0	3,381	290,803	294,184					34
795.0	41,411	3,577,596	3,619,007					35
	85,897,343	1,695,585,078	1,781,482,421	125,807	13,323,841	1,316,314	14,765,962	36

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Railroad Sub., WY	Carter Creek Sub., WY	138.00	138.00	Wood - H	17.00		1
2	Painter Substation, WY	Natural Gas Sub., WY	138.00	138.00	Wood - H	5.00		1
3	Grace Plant, ID	Termnl. Sub., UT (103-104)	138.00	138.00	Steel - S	42.00		2
4	Grace Point, ID	Termnl. Sub., UT (103-104)	138.00	138.00	Wood - H	211.00		2
5	Grace Plant, ID	Terminal Sub., UT (105)	138.00	138.00	Wood - H	143.00		2
6	Grace Plant, ID	Soda Plant, ID	138.00	138.00	Wood - H	8.00	4.00	2
7	Oneida Plant, ID	Ovid Substation, ID	138.00	138.00	Wood - H	23.00		1
8	Antelope Substation, ID	Scoville Sub., ID	138.00	138.00	Wood - H	1.00		1
9	Soda Plant, Idaho	Monsanto Sub., ID	138.00	138.00	Wood - H	8.00		1
10	Caribou Substation, ID	Grace Plant, ID	138.00	138.00	Wood - H	16.00		1
11	Caribou Substation, ID	Becker Substation, ID	138.00	138.00	Wood - H	5.00		1
12	Treasureton Sub., ID	Franklin Sub., ID	138.00	138.00	Wood - H & S	10.00		1
13	Franklin Substation, ID	Smithfield Sub., UT	138.00	138.00	Wood - H	25.00		1
14	Midvalley Substation, UT	Thirty South Sub., UT	138.00	138.00	Wood - H	1.00		1
15	Angel Substation, UT	Smith's UT	138.00	138.00	Wood - H	1.00		1
16	Terminal Substation, UT	30 South Switch Rack, UT	138.00	138.00	Steel - S	7.00		1
17	Jordan, UT	Terminal Substation, UT	138.00	138.00	Wood - H	6.00		1
18	Wheelon Substation, UT	American Falls Sub., UT	138.00	138.00	Wood - H	82.00		1
19	Cutler Plant, UT	Wheelon Substation, UT	138.00	138.00	Wood - H	1.00		1
20	Terminal Substation, UT	Helper Substation, UT	138.00	138.00	Wood - H	116.00		1
21	Hale Plant, UT	Nebo Substation, UT	138.00	138.00	Wood - H	54.00		1
22	Carbon Plant, UT	Helper Substation, UT	138.00	138.00	Wood - H	2.00		1
23	Terminal Substation, UT	Tooele Substation, UT	138.00	138.00	Wood - H	42.00		1
24	Wheelon Substation, UT	Smithfield Sub., UT	138.00	138.00	Wood - H	19.00	1.00	2
25	Helper Substation, UT	Moab Substation, UT	138.00	138.00	Wood - H	118.00		1
26	Ninetieth South Sub, UT	Carbon Plant, UT	138.00	138.00	Wood - H	75.00		2
27	Terminal Substation, UT	Ninetieth South Sub, UT	138.00	138.00	Wood - H	16.00		2
28	30 South Switch Rack, UT	McClelland Sub., UT	138.00	138.00	Wood - SP	6.00		1
29	Moab Substation, UT	Pinto Substation, UT	138.00	138.00	Wood - H	68.00		1
30	Pinto Substation, UT	Abajo, UT	138.00	138.00	Wood - H	45.00		1
31	Carbon Plant, UT	Ashley Substation, UT	138.00	138.00	Wood - H	92.00		1
32	McClelland Sub., UT	Cottonwood Sub., UT	138.00	138.00	Wood - SP	6.00		1
33	Ashley Substation, UT	Vernal Substation, UT	138.00	138.00	Wood - H	12.00		1
34	Sigurd Substation, UT	West Cedar Substation, UT	138.00	138.00	Wood - H	120.00		1
35	Ben Lomond Sub., UT	El Monte Substation, UT	138.00	138.00	Wood - H Sub	19.00		1
36					TOTAL	15,494.00	777.00	210

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of <u>2007/Q4</u>
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TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795.0	72,622	3,821,010	3,893,632					1
795.0	-12,424	-278,836	-291,260					2
795.0	765,186	13,267,187	14,032,373					3
795.0								4
250.0	132,960	16,032,079	16,165,039					5
795.0	3,290	157,216	160,506					6
336.0	4,817	596,581	601,398					7
397.5	149	41	190					8
397.5	2,555	295,902	298,457					9
795.0	18,284	420,886	439,170					10
397.5	14,424	145,941	160,365					11
795.0	39,101	541,498	580,599					12
397.5	47,613	1,094,655	1,142,268					13
		192,647	192,647					14
		20,229	20,229					15
500.0	1,837	1,256,746	1,258,583					16
	661,447	1,776,215	2,437,662					17
250.0	118,180	6,191,321	6,309,501					18
250.0		69,072	69,072					19
250.0	458,799	12,490,719	12,949,518					20
397.5	27,545	4,607,792	4,635,337					21
954.0	786	150,403	151,189					22
397.5	9,460	8,407,186	8,416,646					23
397.5	188,018	1,056,437	1,244,455					24
397.5	33,968	3,033,558	3,067,526					25
795.0	345,836	5,622,147	5,967,983					26
1272.0	426,746	1,228,422	1,655,168					27
795.0	58,030	1,564,316	1,622,346					28
397.5	40,115	1,070,458	1,110,573					29
397.5	100,353	2,100,398	2,200,751					30
397.5	80,861	1,750,314	1,831,175					31
795.0	13,733	1,500,760	1,514,493					32
397.5	5,546	325,444	330,990					33
397.5	62,155	3,548,776	3,610,931					34
795.0	18,845	850,357	869,202					35
	85,897,343	1,695,585,078	1,781,482,421	125,807	13,323,841	1,316,314	14,765,962	36

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Cottonwood Sub., UT	Ninetieth South Sub, UT	138.00	138.00	Wood - SP	11.00		1
2	Terminal Substation, UT	Rowley Substation, UT	138.00	138.00	Wood - H	56.00		1
3	Huntington Plant, UT	McFadden Substation, UT	138.00	138.00	Wood - H	7.00		1
4	Ben Lomond Sub., UT	El Monte Substation, UT	138.00	138.00	Wood - H	13.00		1
5	Cottonwood Sub., UT	Silvercreek Sub., UT	138.00	138.00	Wood - SP	37.00		1
6	Ninetieth South Sub, UT	Taylorville Sub., UT	138.00	138.00	Wood - SP	9.00		1
7	Gadsby Plant, UT	McClelland Sub., UT	138.00	138.00	Wood - SP	4.00		1
8	Ninetieth South Sub, UT	Oquirrh Substation, UT	138.00	138.00	Wood - SP	10.00		2
9	Nebo, UT	Jerusalem, UT	138.00	138.00	Wood Tower	26.00		1
10	Ben Lomond Sub., UT	Western Zircon Sub., UT	138.00	138.00	Wood - H	14.00		1
11	Tooele Substation, UT	Oquirrh Substation, UT	138.00	138.00	Wood - SP	21.00		1
12	Wheelon Substation, UT	Nucor Steel Sub., UT	138.00	138.00	Wood - H	14.00	4.00	1
13	Nebo Substation, UT	Martin-Marietta Sub., UT	138.00	138.00	Wood - H	30.00		1
14	West Cedar Sub., UT	Middleton Substation., UT	138.00	138.00	Wood - H	69.00		1
15	Gadsby Plant, UT	Terminal Substation, UT	138.00	138.00	Wood - H	6.00		1
16	Oquirrh Substation, UT	Kennecott Sub., UT	138.00	138.00	Wood - H	4.00		1
17	Oquirrh Substation, UT	Barney Substation, UT	138.00	138.00	Wood - HS	7.00		2
18	West Cedar Sub., UT	Pepcon Substation, UT	138.00	138.00	Wood - SP	13.00		1
19	Taylorville Substation, UT	Mid-Valley Substation, UT	138.00	138.00	Steel - SP	5.00		1
20	Warren Substation, UT	Kimberly Clark Sub., UT	138.00	138.00	Wood - HP	1.00		1
21	Honeyville, UT	Promontory, UT	138.00	138.00	Wood Tower	22.00		1
22	Ninetieth South Sub, UT	Hale Plant, UT	138.00	138.00	Wood Tower	47.00		1
23	Dumas, UT	Bimple, UT	138.00	138.00	Wood Tower	4.00		
24	Columbia Sub, UT	Sunnyside Co. Gen., UT	138.00	138.00	Wood Tower	2.00		1
25	Syracuse Sub, UT	Ben Lomond Sub, UT	138.00	138.00	Steel- D-P	26.00		1
26	Hale Plant, UT	Midway Sub, UT	138.00	138.00	Wood - H	19.00		1
27	Jordan 138 kV, UT	Fifth West 138 kV, UT	138.00	138.00	Steel Tower	1.00		1
28	Gadsby 138 kV, UT	Jordan 138 kV, UT	138.00	138.00	Steel Tower	1.00		1
29	Panther, UT	Willow Creek, UT	138.00	138.00	Wood Tower	1.00		1
30	Hammer Substation, UT	Butterville Substation, UT	138.00	138.00	Wood Tower	5.00		1
31	Midway Substation, UT	Silver Creek Sub, UT	138.00	138.00	Wood Tower	14.00		1
32	Midway Substation, UT	Cottonwood Sub, UT	138.00	138.00	Wood Tower	10.00		1
33	McFadden Substation, UT	Blackhawk Substation, UT	138.00	138.00	Wood - H	11.00		1
34	West Valley Sub., UT	Keams Substation, UT	138.00	138.00	Wood - SP	2.00		1
35	Syracuse Substation, UT	Clearfield South Sub., UT	138.00	138.00	Wood - SP	1.00		1
36					TOTAL	15,494.00	777.00	210

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795.0	549,064	2,230,643	2,779,707					1
795.0	222,286	2,283,128	2,505,414					2
397.5	265	238,883	239,148					3
795.0	24,901	1,017,499	1,042,400					4
397.5	177,824	6,159,264	6,337,088					5
795.0	5,178	2,550,199	2,555,377					6
795.0	56,759	925,590	982,349					7
795.0	243,445	3,548,477	3,791,922					8
397.5	253,539	2,264,963	2,518,502					9
250.0	96,457	968,211	1,064,668					10
795.0	252,891	3,057,455	3,310,346					11
795.0	46,947	909,120	956,067					12
397.5	66,452	1,796,523	1,862,975					13
397.5	25,148	2,178,964	2,204,112					14
1272.0	668,771	810,473	1,479,244					15
795.0		251,543	251,543					16
795.0	16,668	457,439	474,107					17
795.0	43,590	1,088,222	1,131,812					18
1272.0	33,466	2,500,072	2,533,538					19
297.5	14,722	141,422	156,144					20
397.5	475,682	2,874,162	3,349,844					21
397.5	146,425	7,793,509	7,939,934					22
397.5		3,136,585	3,136,585					23
397.5	-41	2	-39					24
1272.0		353,104	353,104					25
397.5	246,503	4,038,881	4,285,384					26
1272.0	17	1,104,840	1,104,857					27
1272.0	755	381,900	382,655					28
397.5		40,890	40,890					29
	188,391	3,364,794	3,553,185					30
		2,755,012	2,755,012					31
	690,025	5,581,573	6,271,598					32
		1,747,452	1,747,452					33
		268,234	268,234					34
		677,376	677,376					35
	85,897,343	1,695,585,078	1,781,482,421	125,807	13,323,841	1,316,314	14,765,962	36

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Farmington Substation, UT	Parrish Substation, UT	138.00	138.00	Steel - DC	5.00		1
2	Midvalley Substation, UT	Cottonwood Substation, UT	138.00	138.00	Wood - DC	5.00		1
3	Taylorville Substation, UT	West Valley Substation, UT	138.00	138.00	Steel - DC	3.00	3.00	1
4	Dynamo Sub, UT	Tri-City Sub, UT	138.00	138.00	Wood - SP	2.00		2
5	Oquirrh Sub, UT	Tri-City Sub, UT	138.00	138.00	Wood - SP	22.00		2
6	Bridgerland Sub, UT	Green Canyon Sub, UT	138.00	138.00	Wood - SP	16.00		1
7	138 kV expenses							
8								
9	Subtotal 138 kV					2,122.00	12.00	90
10								
11								
12	All 115 kV lines		115.00	115.00	Wood & Steel	1,548.00		
13	All 69 kV lines		69.00	69.00	Wood & Steel	2,962.00	1.00	
14	All 57 kV lines		57.00	57.00	Wood & Steel	113.00		
15	All 46 kV lines		46.00	46.00	Wood & Steel	2,615.00		
16								
17								
18	Unclassified Plant at 12/31							
19	Chappel Creek Unclassified	Plant	230.00	230.00	Wood - H	35.00		1
20	Craven Creek Unclassified	Plant	230.00	230.00	Wood - H	3.00		
21	Marengo Wind Plant Trans	Unclassified Plant	230.00	230.00	Wood H Frame	4.00		1
22	Blundell Steam Plant	Unclassified Plant	69.00	69.00	Wood SP			1
23	Unclassified Plant (Under	\$1,000,000 Projects)						
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	15,494.00	777.00	210

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
		902,058	902,058					1
		4,655,525	4,655,525					2
		2,002,980	2,002,980					3
2-795		9,221,850	9,221,850					4
1557		41,207,670	41,207,670					5
1272		9,233,887	9,233,887					6
				9	1,479,297	86,275	*****	7
								8
	8,607,533	240,037,773	248,645,306	9	1,479,297	86,275	*****	9
								10
								11
	3,510,355	126,231,356	129,741,711	17,044	2,482,147	323,319	*****	12
	3,354,067	212,041,657	215,395,724	16,400	1,735,641	119,263	*****	13
	41,234	8,169,256	8,210,490	4	4,464	331	*****	14
	4,451,705	184,802,664	189,254,369	2,366	2,460,346	40,095	*****	15
								16
								17
								18
1272		11,499,447	11,499,447					19
		826,735	826,735					20
795		1,823,720	1,823,720					21
397		520,637	520,637					22
		6,188,947	6,188,947					23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	85,897,343	1,695,585,078	1,781,482,421	125,807	13,323,841	1,316,314	14,765,962	36

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
PacifiCorp			
FOOTNOTE DATA			

Schedule Page: 422 Line No.: 4 Column: a

The Alvey - Dixonville 500kV line is jointly owned by the respondent and the Bonneville Power Administration ("the BPA"). Ownership of the line is as follows: PacifiCorp 50.0%, the BPA 50.0%. Cost reported for this line reflects the respondents 50.0% share. Operation and maintenance costs are shared between the two parties and responsibility is as follows: PacifiCorp 58.0% and the BPA 42.0%.

Schedule Page: 422 Line No.: 6 Column: a

The Dixonville - Meridian 500kV line is jointly owned by the respondent and the Bonneville Power Administration ("the BPA"). Ownership of the line is as follows: PacifiCorp 50.0%, the BPA 50.0%. Cost reported for this line reflects the respondents 50.0% share. Operation and maintenance costs are shared between the two parties and responsibility is as follows: PacifiCorp 58.0% and the BPA 42.0%.

Schedule Page: 422 Line No.: 7 Column: a

The Colstrip 4 - Switchyard 500kV line is jointly owned by the respondent, NorthWestern Corporation, Puget Sound Power & Light, Washington Water Power Company and Portland General Electric. Ownership of the line is as follows: PacifiCorp 6.8%, all others 93.2%. Plant cost and operation and maintenance costs reported for this line reflects the respondent's share.

Schedule Page: 422 Line No.: 8 Column: a

The Colstrip - Broadview A 500kV line is jointly owned by the respondent, NorthWestern Corporation, Puget Sound Power & Light, Washington Water Power Company and Portland General Electric. Ownership of the line is as follows: PacifiCorp 6.8%, all others 93.2%. Plant cost and operation and maintenance costs reported for this line reflects the respondent's share.

Schedule Page: 422 Line No.: 9 Column: a

The Colstrip - Broadview B 500kV line is jointly owned by the respondent, NorthWestern Corporation, Puget Sound Power & Light, Washington Water Power Company and Portland General Electric. Ownership of the line is as follows: PacifiCorp 6.8%, all others 93.2%. Plant cost and operation and maintenance costs reported for this line reflects the respondent's share.

Schedule Page: 422 Line No.: 10 Column: a

The Broadview - Townsend A 500kV line is jointly owned by the respondent, NorthWestern Corporation, Puget Sound Power & Light, Washington Water Power Company and Portland General Electric. Ownership of the line is as follows: PacifiCorp 8.1%, all others 91.9%. Plant cost and operation and maintenance costs reported for this line reflects the respondent's share.

Schedule Page: 422 Line No.: 11 Column: a

The Broadview - Townsend B 500kV line is jointly owned by the respondent, NorthWestern Corporation, Puget Sound Power & Light, Washington Water Power Company and Portland General Electric. Ownership of the line is as follows: PacifiCorp 8.1%, all others 91.9%. Plant cost and operation and maintenance costs reported for this line reflects the respondent's share.

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(Next Page is 424)

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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TRANSMISSION LINES ADDED DURING YEAR

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

Line No.	LINE DESIGNATION		Line Length in Miles (c)	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)		Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	BDO Sub, UT	Warren-Kimberly Clark, UT	1.24	Wood SP	15.00	1	1
2	Green Canyon Sub, UT	Bridgerland Sub, UT	16.00	Wood SP	15.00	1	1
3	Camp Williams, UT	Mona, UT	50.00	Steel Dbl Ckt	10.00	2	2
4	Chappel Creek, WY	Jonah Field/Bridger, WY	35.00	Wood H Frame	10.00	1	1
5	Craven Creek, WY	Enterprise/Pioneer, WY	3.00	Wood H Frame	12.00	1	1
6	McClelland, UT	Emigration, UT	1.40	Wood Db Ckt	19.00	2	2
7	Meridian, OR	Lone Pine, OR	2.70	Wood H Frame	12.00	1	1
8	Timp, UT	Cherrywood, UT	1.68	Wood SP	14.00	1	1
9	Sunrise, UT	Oquirrh, UT	2.37	Steel SP	14.00	2	2
10	Dynamo, UT	Tri-City, UT	2.42	Wood SP	15.00	2	2
11	Bangerter, UT	Oquirrh, UT	3.27	Wood SP	14.00	2	2
12	70th South, UT	West Jordan, UT	1.50	Wood Db Ckt	18.00	1	2
13	Marengo Wind Plant, WA	Talbot Sub, WA	4.00	Wood H Frame	10.00	1	1
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
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32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		124.58		178.00	18	19

Name of Respondent PacifiCorp			This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008		Year/Period of Report End of 2007/Q4		
TRANSMISSION LINES ADDED DURING YEAR (Continued)									
costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).									
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.									
CONDUCTORS			Voltage KV (Operating) (k)	LINE COST				Line No.	
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)		Total (p)
397.5	ACSR	Horizon/10'	138		625,472	625,471		1,250,943	1
1272	ACSR	Vertical/10'	138		6,291,047	2,942,840		9,233,887	2
1272	ACSR	Vertical/25'	345			9,578,059		9,578,059	3
1272	ACSR	Horiz/19.6'	230		6,824,922	4,674,525		11,499,447	4
1272	ACSR	Horiz/17.5'	230		413,368	413,367		826,735	5
1557	ACSR	Vertical/10'	138			682,523		682,523	6
1272	ACSR	Horizon/12'	230		185,431	669,877		855,308	7
1557	ACSR	Vertical/10'	138		5,186,399	751,773		5,938,172	8
1557	ACSR	Vertical/10'	138		22,960,298	5,558,269		28,518,567	9
2-795	ACSR	Vertical/10'	138		5,055,418	4,166,432		9,221,850	10
1557	ACSR	Vertical/10'	138						11
1557	ACSR	Vertical/10'	138		1,615,077	273,460		1,888,537	12
795	ACSR	Vertical/12'	230		911,860	911,860		1,823,720	13
									14
									15
									16
									17
									18
									19
									20
									21
									22
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									36
									37
									38
									39
									40
									41
									42
									43
					50,069,292	31,248,456		81,317,748	44

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
FOOTNOTE DATA			

Schedule Page: 424 Line No.: 11 Column: o

Costs included in Sunrise - Oquirrh line above.

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(Next Page is 426)

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	California				
2	BELMONT	DISTRIBUTION-UNATTEN	69.00	12.47	
3	BIG SPRINGS	DISTRIBUTION-UNATTEN	69.00	12.47	
4	CANBY #2	DISTRIBUTION-UNATTEN	69.00	2.40	
5	CASTELLA	DISTRIBUTION-UNATTEN	69.00	2.40	
6	CLEAR LAKE	DISTRIBUTION-UNATTEN	69.00	12.47	
7	CRESCENT CITY	DISTRIBUTION-UNATTEN	12.47	4.16	
8	DOG CREEK	DISTRIBUTION-UNATTEN	69.00	2.40	
9	DORRIS	DISTRIBUTION-UNATTEN	69.00	12.47	
10	FORT JONES	DISTRIBUTION-UNATTEN	69.00	12.47	
11	GASQUET	DISTRIBUTION-UNATTEN	115.00	12.47	
12	GREENHORN	DISTRIBUTION-UNATTEN	69.00	12.47	
13	HAMBURG	DISTRIBUTION-UNATTEN	69.00	2.40	
14	HAPPY CAMP	DISTRIBUTION-UNATTEN	69.00	12.47	
15	HORNBROOK	DISTRIBUTION-UNATTEN	69.00	12.47	
16	INTERNATIONAL PAPER	DISTRIBUTION-UNATTEN	69.00	2.40	
17	LAKE EARL	DISTRIBUTION-UNATTEN	69.00	12.47	
18	LITTLE SHASTA	DISTRIBUTION-UNATTEN	69.00	7.20	
19	LUCERNE	DISTRIBUTION-UNATTEN	69.00	12.47	
20	MACDOEL	DISTRIBUTION-UNATTEN	69.00	20.80	
21	MCCLOUD	DISTRIBUTION-UNATTEN	69.00	12.47	
22	MILLER REDWOOD	DISTRIBUTION-UNATTEN	69.00	12.47	
23	MONTAGUE	DISTRIBUTION-UNATTEN	69.00	12.47	
24	MOUNT SHASTA	DISTRIBUTION-UNATTEN	69.00	12.47	
25	NEWELL	DISTRIBUTION-UNATTEN	69.00	12.47	
26	NORTH DUNSMUIR	DISTRIBUTION-UNATTEN	69.00	12.47	
27	NORTHCREST	DISTRIBUTION-UNATTEN	69.00	12.47	
28	NUTGLADE	DISTRIBUTION-UNATTEN	69.00	2.40	
29	PATRICKS CREEK	DISTRIBUTION-UNATTEN	115.00	7.20	
30	PEREZ	DISTRIBUTION-UNATTEN	69.00	12.47	
31	REDWOOD	DISTRIBUTION-UNATTEN	69.00	12.47	
32	SCOTT BAR	DISTRIBUTION-UNATTEN	69.00	12.47	
33	SEIAD	DISTRIBUTION-UNATTEN	69.00	12.47	
34	SHASTINA	DISTRIBUTION-UNATTEN	69.00	20.80	
35	SHOTGUN CREEK	DISTRIBUTION-UNATTEN	69.00	12.47	
36	SIMONSON	DISTRIBUTION-UNATTEN	69.00	12.47	
37	SMITH RIVER	DISTRIBUTION-UNATTEN	69.00	12.47	
38	SNOW BRUSH	DISTRIBUTION-UNATTEN	69.00	7.20	
39	SOUTH DUNSMUIR	DISTRIBUTION-UNATTEN	69.00	4.16	
40	TULELAKE	DISTRIBUTION-UNATTEN	69.00	12.47	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
						1
25	1					2
6	1					3
1	3					4
2	3					5
4	3					6
3	6					7
	1					8
8	3					9
6	1					10
9	1					11
13	1					12
1	1					13
8	3					14
4	3					15
9	3					16
13	1					17
2	3					18
4	1					19
31	2					20
6	1					21
4	3					22
6	1					23
16	4					24
8	3					25
6	6					26
20	4					27
2	3					28
1	1					29
2	3					30
9	3					31
2	3					32
2	3					33
18	3					34
1	1					35
5	3					36
6	3					37
	3					38
2	3					39
20	1					40

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	TUNNEL	DISTRIBUTION-UNATTEN	69.00	12.47	
2	TURKEY HILL	DISTRIBUTION-UNATTEN	69.00	12.47	
3	WALKER BRYAN	DISTRIBUTION-UNATTEN	69.00	12.47	
4	WEED	DISTRIBUTION-UNATTEN	69.00	12.47	
5	YUBA	DISTRIBUTION-UNATTEN	69.00	12.47	
6	YUOK	DISTRIBUTION-UNATTEN	69.00	12.47	
7	Total		3140.47	484.96	
8	NUMBER OF SUBSTATIONS UNATTENDED - 45				
9					
10	ALTURAS	T/D-UNATTENDED	115.00	12.47	69.00
11	FALL CREEK HYDRO/	T/D-UNATTENDED	69.00	2.30	
12	YREKA	T/D-UNATTENDED	115.00	12.47	69.00
13	Total		299.00	27.24	138.00
14	NUMBER OF SUBSTATIONS T/D UNATTENDED - 3				
15					
16	AGER	TRANSMISSION-ATTEND	115.00	69.00	
17	COPCO #1 HYDRO PLANT	TRANSMISSION-ATTEND	69.00	2.30	
18	COPCO #2 HYDRO PLANT	TRANSMISSION-ATTEND	69.00	6.60	
19	COPCO #2	TRANSMISSION-ATTEND	69.00	12.47	
20	COPCO #2	TRANSMISSION-ATTEND	230.00	115.00	
21	Total		552.00	205.37	
22	NUMBER OF SUBSTATIONS TRANS ATTEND - 5				
23					
24	CRAG VIEW	TRANSMISSION-UNATTEN	115.00	69.00	
25	DEL NORTE	TRANSMISSION-UNATTEN	115.00	69.00	
26	IRON GATE HYDRO PLANT	TRANSMISSION-UNATTEN	69.00	6.60	
27	WEED JUNCTION	TRANSMISSION-UNATTEN	115.00	69.00	
28	Total		414.00	213.60	
29	NUMBER OF SUBSTATIONS TRANS UNATTENDED - 4				
30					
31	Idaho				
32	ALEXANDER	DISTRIBUTION-UNATTEN	46.00	12.47	
33	AMMON	DISTRIBUTION-UNATTEN	69.00	12.47	
34	ANDERSON	DISTRIBUTION-UNATTEN	69.00	12.47	
35	ARCO	DISTRIBUTION-UNATTEN	69.00	12.47	
36	ARIMO	DISTRIBUTION-UNATTEN	46.00	12.47	
37	BANCROFT	DISTRIBUTION-UNATTEN	46.00	12.47	
38	BELSON	DISTRIBUTION-UNATTEN	69.00	12.47	
39	BERENICE	DISTRIBUTION-UNATTEN	69.00	12.47	
40	CAMAS	DISTRIBUTION-UNATTEN	69.00	12.47	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
6	6					1
13	3					2
7	1					3
13	1					4
4	3					5
4	3					6
332	113					7
						8
						9
31	4					10
3	3					11
95	2					12
129	9					13
						14
						15
5	3					16
28	6	2				17
60	3	1				18
2	3					19
125	1					20
220	16	3				21
						22
						23
19	3					24
150	2					25
19	1					26
38	3					27
226	9					28
						29
						30
						31
4	1					32
11	1					33
20	1					34
6	1					35
8	1					36
4	1					37
13	1					38
11	1					39
14	1					40

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	CANYON CREEK	DISTRIBUTION-UNATTEN	69.00	24.90	
2	CHESTERFIELD	DISTRIBUTION-UNATTEN	46.00	12.47	
3	CINDER BUTTE	DISTRIBUTION-UNATTEN	161.00	12.47	
4	CLEMENTS	DISTRIBUTION-UNATTEN	69.00	12.47	
5	CLIFTON	DISTRIBUTION-UNATTEN	46.00	12.47	
6	COVE	DISTRIBUTION-UNATTEN	46.00	6.60	
7	DOWNEY	DISTRIBUTION-UNATTEN	46.00	12.47	
8	DUBOIS	DISTRIBUTION-UNATTEN	69.00	12.47	
9	EASTMONT	DISTRIBUTION-UNATTEN	69.00	12.47	
10	EGIN	DISTRIBUTION-UNATTEN	69.00	12.47	
11	EIGHT MILE	DISTRIBUTION-UNATTEN	46.00	12.47	
12	GEORGETOWN	DISTRIBUTION-UNATTEN	69.00	12.47	
13	GRACE CITY STATION	DISTRIBUTION-UNATTEN	46.00	12.47	
14	HAMER	DISTRIBUTION-UNATTEN	69.00	12.47	
15	HAYES	DISTRIBUTION-UNATTEN	69.00	12.47	
16	HENRY	DISTRIBUTION-UNATTEN	46.00	12.47	
17	HOLBROOD	DISTRIBUTION-UNATTEN	69.00	12.47	
18	HOOPES	DISTRIBUTION-UNATTEN	69.00	12.47	
19	HORSLEY	DISTRIBUTION-UNATTEN	46.00	12.47	
20	IDAHO FALLS	DISTRIBUTION-UNATTEN	46.00	12.47	
21	INDIAN CREEK	DISTRIBUTION-UNATTEN	69.00	12.47	
22	JEFFCO	DISTRIBUTION-UNATTEN	69.00	24.90	
23	KETTLE	DISTRIBUTION-UNATTEN	69.00	24.90	
24	LAVA	DISTRIBUTION-UNATTEN	46.00	12.47	
25	LUND	DISTRIBUTION-UNATTEN	46.00	12.47	
26	MCCAMMON	DISTRIBUTION-UNATTEN	46.00	12.47	
27	MENAN	DISTRIBUTION-UNATTEN	69.00	12.47	
28	MERRILL	DISTRIBUTION-UNATTEN	69.00	12.47	
29	MILLER	DISTRIBUTION-UNATTEN	69.00	12.47	
30	MONTPELIER	DISTRIBUTION-UNATTEN	69.00	12.47	
31	MOODY	DISTRIBUTION-UNATTEN	69.00	24.90	
32	NEWDALE	DISTRIBUTION-UNATTEN	69.00	12.47	
33	OSGOOD	DISTRIBUTION-UNATTEN	69.00	12.47	
34	PRESTON	DISTRIBUTION-UNATTEN	46.00	12.47	
35	RAYMOND	DISTRIBUTION-UNATTEN	69.00	12.47	
36	RENO	DISTRIBUTION-UNATTEN	69.00	12.47	
37	REXBURG	DISTRIBUTION-UNATTEN	69.00	12.47	
38	RIRIE	DISTRIBUTION-UNATTEN	69.00	12.47	
39	ROBERTS	DISTRIBUTION-UNATTEN	69.00	12.47	
40	RUDY	DISTRIBUTION-UNATTEN	69.00	12.47	

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SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
20	1					1
5	1					2
30	1	1				3
5	1					4
4	1					5
21	4					6
5	1					7
13	1					8
14	1					9
14	1					10
3	1					11
6	1					12
5	1					13
14	1					14
9	1					15
3	1					16
6	1					17
9	1					18
4	1					19
20	1					20
3	1					21
22	1					22
14	1					23
3	1					24
5	1					25
3	1					26
11	1					27
20	1					28
5	1					29
8	1					30
14	1					31
20	1					32
20	1					33
13	1					34
2	1					35
20	1					36
33	2					37
9	1					38
8	1					39
7	1					40

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	SAND CREEK	DISTRIBUTION-UNATTEN	69.00	12.47	
2	SANDUNE	DISTRIBUTION-UNATTEN	69.00	24.90	
3	SHELLEY	DISTRIBUTION-UNATTEN	46.00	12.47	
4	SMITH	DISTRIBUTION-UNATTEN	69.00	12.47	
5	SODA	DISTRIBUTION-UNATTEN	138.00	7.20	
6	SOUTH FORK	DISTRIBUTION-UNATTEN	69.00	12.47	
7	SPUD	DISTRIBUTION-UNATTEN	46.00	12.47	
8	ST. CHARLES	DISTRIBUTION-UNATTEN	69.00	12.47	
9	SUGAR CITY	DISTRIBUTION-UNATTEN	69.00	12.47	
10	SUNNYDELL	DISTRIBUTION-UNATTEN	69.00	12.47	
11	TANNER	DISTRIBUTION-UNATTEN	46.00	12.47	
12	TARGHEE	DISTRIBUTION-UNATTEN	46.00	12.47	
13	THORNTON	DISTRIBUTION-UNATTEN	69.00	12.47	
14	UCON	DISTRIBUTION-UNATTEN	69.00	12.47	
15	WATKINS	DISTRIBUTION-UNATTEN	69.00	12.47	
16	WEBSTER	DISTRIBUTION-UNATTEN	69.00	12.47	
17	WESTON	DISTRIBUTION-UNATTEN	46.00	12.47	
18	WINDSPER	DISTRIBUTION-UNATTEN	69.00	24.90	
19	Total		4301.00	898.93	
20	NUMBER OF SUBSTATIONS DIST UNATTENDED - 67				
21					
22	MALAD	T/D-UNATTENDED	138.00	46.00	12.47
23	MUD LAKE	T/D-UNATTENDED	69.00	12.47	
24	RIGBY	T/D-UNATTENDED	161.00	12.47	69.00
25	SAINT ANTHONY	T/D-UNATTENDED	69.00	46.00	12.47
26	Total		437.00	116.94	93.94
27	NUMBER OF SUBSTATIONS T/D UNATTENDED - 4				
28					
29	GRACE HYDRO	TRANSMISSION-ATTEND	138.00	46.00	6.60
30	Total		138.00	46.00	6.60
31	NUMBER OF SUBSTATIONS TRANS ATTENDED - 1				
32					
33	AMPS	TRANSMISSION-UNATTEN	230.00	69.00	
34	ANTELOPE	TRANSMISSION-UNATTEN	230.00	161.00	
35	ASHTON PLANT	TRANSMISSION-UNATTEN	46.00	2.40	
36	BIG GRASSY	TRANSMISSION-UNATTEN	161.00	69.00	
37	BONNEVILLE	TRANSMISSION-UNATTEN	161.00	69.00	
38	CARIBOU	TRANSMISSION-UNATTEN	138.00	46.00	
39	CONDA	TRANSMISSION-UNATTEN	138.00	46.00	
40	FISH CREEK	TRANSMISSION-UNATTEN	161.00	46.00	

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SUBSTATIONS (Continued)

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

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Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
40	2					1
20	1					2
20	1					3
20	1					4
22	1					5
14	1					6
8	1					7
5	1					8
13	1					9
13	1					10
4	1					11
4	1					12
7	1					13
7	1					14
14	1					15
20	1					16
4	1					17
20	1					18
796	72	1				19
						20
						21
71	4	1				22
14	1					23
189	4					24
40	2					25
314	11	1				26
						27
						28
115	4					29
115	4					30
						31
						32
75	2	1				33
250	1					34
25	3					35
67	1					36
67	1					37
27	1					38
67	1					39
25	3					40

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SUBSTATIONS

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- Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	FRANKLIN	TRANSMISSION-UNATTEN	138.00	46.00	
2	GOSHEN	TRANSMISSION-UNATTEN	345.00	161.00	46.00
3	JEFFERSON	TRANSMISSION-UNATTEN	161.00	69.00	
4	LIFTON HYDRO	TRANSMISSION-UNATTEN	69.00	2.30	
5	ONEIDA	TRANSMISSION-UNATTEN	138.00	12.50	
6	OVID	TRANSMISSION-UNATTEN	138.00	69.00	
7	SCOVILLE	TRANSMISSION-UNATTEN	138.00	69.00	46.00
8	SUGARMILL	TRANSMISSION-UNATTEN	161.00	46.00	69.00
9	TREASURETON	TRANSMISSION-UNATTEN	230.00	138.00	
10	Total		2783.00	1121.20	161.00
11	NUMBER OF SUBSTATIONS TRANS UNATTENDED - 17				
12					
13	Oregon				
14	26TH STREET	DISTRIBUTION-UNATTEN	20.80	4.16	
15	35TH STREET	DISTRIBUTION-UNATTEN	20.80	2.40	
16	AGNESS AVE	DISTRIBUTION-UNATTEN	115.00	12.47	
17	ALDERWOOD	DISTRIBUTION-UNATTEN	69.00	12.47	
18	ARLINGTON	DISTRIBUTION-UNATTEN	69.00	12.47	
19	ATHENA	DISTRIBUTION-UNATTEN	69.00	12.47	
20	BANDON TIE	DISTRIBUTION-UNATTEN	20.80	12.47	
21	BEACON	DISTRIBUTION-UNATTEN	69.00	12.47	
22	BEALL LANE	DISTRIBUTION-UNATTEN	115.00	12.47	
23	BEATTY	DISTRIBUTION-UNATTEN	69.00	12.47	
24	BELKNAP	DISTRIBUTION-UNATTEN	69.00	12.47	
25	BLALOCK	DISTRIBUTION-UNATTEN	69.00	12.47	
26	BLOSS	DISTRIBUTION-UNATTEN	115.00	12.47	
27	BLY	DISTRIBUTION-UNATTEN	69.00	12.47	
28	BOISE CASCADE	DISTRIBUTION-UNATTEN	69.00	11.00	
29	BONANZA	DISTRIBUTION-UNATTEN	69.00	12.47	
30	BOND STREET	DISTRIBUTION-UNATTEN	69.00	12.50	
31	BROOKHURST	DISTRIBUTION-UNATTEN	115.00	12.47	
32	BROWNSVILLE	DISTRIBUTION-UNATTEN	69.00	20.80	
33	BRYANT	DISTRIBUTION-UNATTEN	69.00	12.47	
34	BUCHANAN	DISTRIBUTION-UNATTEN	115.00	20.80	
35	BUCKAROO	DISTRIBUTION-UNATTEN	69.00	12.47	
36	CAMPBELL	DISTRIBUTION-UNATTEN	115.00	12.47	
37	CANNON BEACH	DISTRIBUTION-UNATTEN	115.00	12.47	
38	CARNES	DISTRIBUTION-UNATTEN	69.00	12.47	
39	CASEBEER	DISTRIBUTION-UNATTEN	69.00	20.80	
40	CAVEMAN	DISTRIBUTION-UNATTEN	115.00	12.47	

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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
75	1					1
763	8	1				2
233	3					3
6	2					4
40	2					5
30	1					6
76	2					7
168	3					8
533	2					9
2527	37	2				10
						11
						12
						13
5	1					14
30	6					15
25	1					16
25	1					17
5	1					18
9	1					19
8	3	1				20
11	3					21
25	1					22
6	1					23
40	2					24
2	3					25
32	2					26
8	3					27
3	1					28
8	3					29
25	1					30
50	2					31
13	1					32
34	2					33
40	2					34
34	2					35
20	1					36
13	1					37
9	3					38
20	1					39
45	2					40

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	CHERRY LANE	DISTRIBUTION-UNATTEN	69.00	12.47	
2	CHILOQUIN MARKET	DISTRIBUTION-UNATTEN	69.00	12.47	
3	CHINA HAT	DISTRIBUTION-UNATTEN	69.00	12.47	
4	CIRCLE BLVD	DISTRIBUTION-UNATTEN	115.00	20.80	
5	CLEVELAND AVE	DISTRIBUTION-UNATTEN	69.00	12.47	
6	CLINE FALLS HYDRO	DISTRIBUTION-UNATTEN	12.47	2.40	
7	CLOAKE	DISTRIBUTION-UNATTEN	69.00	20.80	
8	COBURG	DISTRIBUTION-UNATTEN	69.00	20.80	
9	COLISEUM	DISTRIBUTION-UNATTEN	20.80	4.16	
10	COLUMBIA	DSITRIBUTION-UNATTEN	115.00	12.47	57.00
11	COOS RIVER	DISTRIBUTION-UNATTEN	115.00	20.80	
12	COQUILLE	DISTRIBUTION-UNATTEN	115.00	20.80	
13	CREEK	DISTRIBUTION-UNATTEN	69.00	34.50	
14	CROOKED RIVER RANCH	DISTRIBUTION-UNATTEN	69.00	20.80	
15	CROWFOOT	DISTRIBUTION-UNATTEN	115.00	12.47	
16	CULLY	DISTRIBUTION-UNATTEN	115.00	12.47	
17	CULVER	DISTRIBUTION-UNATTEN	69.00	12.47	
18	CUTLER CITY	DISTRIBUTION-UNATTEN	20.80	4.16	
19	DAIRY	DISTRIBUTION-UNATTEN	69.00	12.47	
20	DALLAS	DISTRIBUTION-UNATTEN	115.00	20.80	
21	DALREED	DISTRIBUTION-UNATTEN	230.00	34.50	
22	DESCHUTES	DISTRIBUTION-UNATTEN	69.00	12.47	
23	DEVILS LAKE	DISTRIBUTION-UNATTEN	115.00	20.80	
24	DIXON	DISTRIBUTION-UNATTEN	115.00	4.16	
25	DODGE BRIDGE	DISTRIBUTION-UNATTEN	69.00	20.80	
26	EAST VALLEY	DISTRIBUTION-UNATTEN	115.00	12.47	
27	EMPIRE	DISTRIBUTION-UNATTEN	115.00	20.80	
28	ENTERPRISE	DISTRIBUTION-UNATTEN	69.00	12.47	
29	FERN HILL	DISTRIBUTION-UNATTEN	115.00	12.47	
30	FIELDER CREEK	DISTRIBUTION-UNATTEN	115.00	20.80	
31	FOOTHILLS	DISTRIBUTION-UNATTEN	69.00	12.47	
32	FRALEY	DISTRIBUTION-UNATTEN	69.00	12.47	
33	GARDEN VALLEY	DISTRIBUTION-UNATTEN	69.00	20.80	
34	GAZLEY	DISTRIBUTION-UNATTEN	69.00	12.47	
35	GEARHART	DISTRIBUTION-UNATTEN	12.47	4.16	
36	GLENDALE	DISTRIBUTION-UNATTEN	230.00	12.47	
37	GLENEDEN	DISTRIBUTION-UNATTEN	20.80	4.16	
38	GLIDE	DISTRIBUTION-UNATTEN	115.00	12.47	
39	GOLD HILL	DISTRIBUTION-UNATTEN	69.00	12.47	
40	GORDON HOLLOW	DISTRIBUTION-UNATTEN	69.00	12.47	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
25	1					1
5	3					2
25	1					3
80	2					4
45	2					5
1	3					6
20	1					7
1	3					8
9	2					9
55	2	1				10
20	1					11
40	2					12
5	1					13
25	2					14
20	1					15
25	1					16
13	1					17
2	3					18
25	1					19
50	2					20
75	3					21
13	1					22
50	2					23
7	1					24
13	1					25
45	2					26
20	1					27
19	2					28
13	1					29
25	1					30
21	4					31
5	3					32
20	1					33
8	3					34
8	3					35
25	2					36
5	1					37
13	1					38
11	3					39
6	1					40

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4	
SUBSTATIONS						
<p>1. Report below the information called for concerning substations of the respondent as of the end of the year.</p> <p>2. Substations which serve only one industrial or street railway customer should not be listed below.</p> <p>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.</p> <p>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).</p>						
Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)			
			Primary (c)	Secondary (d)	Tertiary (e)	
1	GOSHEN	DISTRIBUTION-UNATTEN	115.00	20.80		
2	GRANT STREET	DISTRIBUTION-UNATTEN	115.00	20.80		
3	GRASS VALLEY	DISTRIBUTION-UNATTEN	20.80	4.16		
4	GREEN	DISTRIBUTION-UNATTEN	69.00	12.47		
5	GRIFFIN CREEK	DISTRIBUTION-UNATTEN	115.00	12.47		
6	HAMAKER	DISTRIBUTION-UNATTEN	69.00	12.47		
7	HARRISBURG	DISTRIBUTION-UNATTEN	69.00	20.80		
8	HENLEY	DISTRIBUTION-UNATTEN	69.00	12.47		
9	HERMISTON	DISTRIBUTION-UNATTEN	69.00	12.47		
10	HILLVIEW	DISTRIBUTION-UNATTEN	115.00	20.80		
11	HINKLE	DISTRIBUTION-UNATTEN	69.00	12.47		
12	HOLLADAY	DISTRIBUTION-UNATTEN	115.00	12.47		
13	HOLLYWOOD	DISTRIBUTION-UNATTEN	115.00	12.47		
14	HOOD RIVER	DISTRIBUTION-UNATTEN	69.00	12.47		
15	HORNET	DISTRIBUTION-UNATTEN	69.00	12.47		
16	INDEPENDENCE	DISTRIBUTION-UNATTEN	69.00	20.80		
17	JACKSONVILLE	DISTRIBUTION-UNATTEN	115.00	12.47	69.00	
18	JEFFERSON	DISTRIBUTION-UNATTEN	69.00	20.80		
19	JEROME PRAIRIE	DISTRIBUTION-UNATTEN	115.00	12.47		
20	JORDAN POINT	DISTRIBUTION-UNATTEN	115.00	12.47		
21	JOSEPH	DISTRIBUTION-UNATTEN	20.80	12.47		
22	JUNCTION CITY	DISTRIBUTION-UNATTEN	69.00	20.80		
23	KENWOOD	DISTRIBUTION-UNATTEN	69.00	12.47		
24	KILLINGWORTH	DISTRIBUTION-UNATTEN	69.00	12.47		
25	KNAPPA SVENSEN	DISTRIBUTION-UNATTEN	115.00	12.47		
26	LAKEPORT	DISTRIBUTION-UNATTEN	69.00	12.47		
27	LAKEVIEW	DISTRIBUTION-UNATTEN	69.00	12.47		
28	LANCASTER	DISTRIBUTION-UNATTEN	69.00	20.80		
29	LEBANON	DISTRIBUTION-UNATTEN	115.00	20.80		
30	LINCOLN	DISTRIBUTION-UNATTEN	115.00	12.47		
31	LOCKHART	DISTRIBUTION-UNATTEN	115.00	20.80		
32	LYONS	DISTRIBUTION-UNATTEN	69.00	20.80		
33	MADRAS	DISTRIBUTION-UNATTEN	69.00	12.47		
34	MALLORY	DISTRIBUTION-UNATTEN	115.00	12.47		
35	MARYS RIVER	DISTRIBUTION-UNATTEN	115.00	20.80		
36	MEDCO	DISTRIBUTION-UNATTEN	115.00	12.47		
37	MEDFORD	DISTRIBUTION-UNATTEN	69.00	12.47		
38	MERLIN	DISTRIBUTION-UNATTEN	115.00	12.47		
39	MERRILL	DISTRIBUTION-UNATTEN	69.00	12.47		
40	MINAM	DISTRIBUTION-UNATTEN	69.00	12.47		

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
20	1					1
45	2					2
1	4					3
25	1					4
20	1					5
8	3					6
13	1					7
6	3					8
40	2					9
45	2					10
20	1					11
75	3					12
50	2					13
40	2					14
20	1					15
20	1					16
75	2					17
13	1					18
20	1					19
20	1					20
6	1	1				21
25	2					22
3	3					23
40	2					24
6	1					25
50	2					26
9	3					27
13	3					28
40	2					29
105	3					30
40	2					31
9	1					32
25	2					33
25	1					34
20	1					35
20	1					36
79	14					37
45	2					38
17	6					39
	1					40

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	MODOC	DISTRIBUTION-UNATTEN	69.00	12.47	
2	MORO	DISTRIBUTION-UNATTEN	20.80	2.40	
3	MURDER CREEK	DISTRIBUTION-UNATTEN	115.00	20.80	
4	MYRTLE CREEK	DISTRIBUTION-UNATTEN	69.00	12.47	
5	MYRTLE POINT	DISTRIBUTION-UNATTEN	115.00	20.80	
6	NELSCOTT	DISTRIBUTION-UNATTEN	20.80	4.16	
7	NEW O'BRIEN	DISTRIBUTION-UNATTEN	115.00	12.47	
8	OAK KNOLL	DISTRIBUTION-UNATTEN	115.00	12.47	
9	OAKLAND	DISTRIBUTION-UNATTEN	115.00	12.47	
10	ORCHARD STREET	DISTRIBUTION-UNATTEN	12.47	4.16	
11	OVERPASS	DISTRIBUTION-UNATTEN	69.00	12.47	
12	PALLETTE	DISTRIBUTION-UNATTEN	69.00	20.80	
13	PARK STREET	DISTRIBUTION-UNATTEN	115.00	12.47	
14	PARKROSE	DISTRIBUTION-UNATTEN	57.00	12.47	
15	PENDLETON	DISTRIBUTION-UNATTEN	69.00	12.47	
16	PILOT ROCK	DISTRIBUTION-UNATTEN	69.00	12.47	
17	POWELL BUTTE	DISTRIBUTION-UNATTEN	115.00	12.47	
18	PRINEVILLE	DISTRIBUTION-UNATTEN	115.00	12.47	
19	PROVOLT	DISTRIBUTION-UNATTEN	69.00	12.47	
20	QUEEN AVE	DISTRIBUTION-UNATTEN	69.00	20.80	
21	RED BLANKET	DISTRIBUTION-UNATTEN	69.00	4.16	
22	REDMOND	DISTRIBUTION-UNATTEN	115.00	12.47	
23	RICH MANUFACTURING	DISTRIBUTION-UNATTEN	57.00	12.47	
24	RIDDLE	DISTRIBUTION-UNATTEN	69.00	12.47	
25	RIDDLE VENEER	DISTRIBUTION-UNATTEN	69.00	12.47	
26	ROGUE RIVER	DISTRIBUTION-UNATTEN	69.00	12.47	
27	ROSEBURG	DISTRIBUTION-UNATTEN	115.00	20.80	
28	ROSS AVE	DISTRIBUTION-UNATTEN	69.00	12.47	
29	ROXY	DISTRIBUTION-UNATTEN	115.00	12.50	
30	RUCH	DISTRIBUTION-UNATTEN	69.00	12.47	
31	RUNNING Y	DISTRIBUTION-UNATTEN	69.00	20.80	
32	RUSSELLVILLE	DISTRIBUTION-UNATTEN	115.00	12.47	
33	SAGE ROAD	DISTRIBUTION-UNATTEN	115.00	12.47	
34	SCENIC	DISTRIBUTION-UNATTEN	115.00	12.47	69.00
35	SCIO	DISTRIBUTION-UNATTEN	69.00	12.47	
36	SEASIDE	DISTRIBUTION-UNATTEN	115.00	12.47	
37	SELMA	DISTRIBUTION-UNATTEN	115.00	12.47	
38	SHASTA WAY	DISTRIBUTION-UNATTEN	12.47	4.16	
39	SHEVLIN PARK	DISTRIBUTION-UNATTEN	69.00	12.50	
40	SIMTAG BOOSTER PUMP	DISTRIBUTION-UNATTEN	34.50	4.16	

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SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
6	3					1
2	3					2
100	4					3
14	1					4
9	1					5
4	1					6
9	1					7
45	2					8
8	1					9
2	3					10
45	2					11
1	1	1				12
40	2					13
39	2					14
46	7	1				15
22	2					16
6	1					17
50	2					18
11	3					19
50	2					20
2	3					21
50	2					22
8	1					23
14	1					24
25	1					25
25	2					26
50	2					27
9	3					28
25	1					29
9	1					30
9	1					31
45	2					32
40	2					33
70	3					34
8	1					35
40	2					36
9	1					37
2	3					38
25	1					39
19	2					40

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	SOUTH DUNES	DISTRIBUTION-UNATTEN	115.00	12.47	
2	SOUTHGATE	DISTRIBUTION-UNATTEN	69.00	20.80	
3	SPRAGUE RIVER	DISTRIBUTION-UNATTEN	69.00	12.47	
4	STATE STREET	DISTRIBUTION-UNATTEN	115.00	20.80	
5	STAYTON	DISTRIBUTION-UNATTEN	69.00	12.47	
6	STEAMBOAT	DISTRIBUTION-UNATTEN	115.00	7.20	
7	STEVENS ROAD	DISTRIBUTION-UNATTEN	115.00	20.80	
8	SUTHERLIN	DISTRIBUTION-UNATTEN	115.00	12.47	
9	SWEET HOME	DISTRIBUTION-UNATTEN	115.00	20.80	
10	TAKELMA	DISTRIBUTION-UNATTEN	115.00	20.80	
11	TALENT	DISTRIBUTION-UNATTEN	69.00	12.47	
12	TEXUM	DISTRIBUTION-UNATTEN	69.00	12.47	
13	TILLER	DISTRIBUTION-UNATTEN	115.00	12.47	
14	TOLO	DISTRIBUTION-UNATTEN	69.00	12.47	
15	UMAPINE	DISTRIBUTION-UNATTEN	69.00	12.47	
16	UMATILLA	DISTRIBUTION-UNATTEN	69.00	12.47	
17	US PLYWOOD	DISTRIBUTION-UNATTEN	20.80	4.16	
18	VERNON	DISTRIBUTION-UNATTEN	69.00	12.47	
19	VILAS	DISTRIBUTION-UNATTEN	115.00	12.47	
20	VILLAGE GREEN	DISTRIBUTION-UNATTEN	115.00	20.80	
21	VINE STREET	DISTRIBUTION-UNATTEN	69.00	20.80	
22	WALLOWA	DISTRIBUTION-UNATTEN	69.00	12.47	
23	WARM SPRINGS	DISTRIBUTION-UNATTEN	69.00	20.80	
24	WARRENTON	DISTRIBUTION-UNATTEN	115.00	12.47	
25	WASCO	DISTRIBUTION-UNATTEN	20.80	4.16	
26	WECOMA BEACH	DISTRIBUTION-UNATTEN	20.80	4.16	
27	WESTERN KRAFT	DISTRIBUTION-UNATTEN	115.00	12.47	
28	WESTON	DISTRIBUTION-UNATTEN	69.00	12.47	
29	WESTSIDE HYDRO	DISTRIBUTION-UNATTEN	69.00	12.47	
30	WEYERHAUSER	DISTRIBUTION-UNATTEN	69.00	12.47	
31	WHITE CITY	DISTRIBUTION-UNATTEN	115.00	12.47	
32	WILLOW COVE	DISTRIBUTION-UNATTEN	34.50	4.16	
33	WINSTON	DISTRIBUTION-UNATTEN	69.00	12.47	
34	YOUNGS BAY	DISTRIBUTION-UNATTEN	115.00	12.47	
35	Total		15039.28	2472.84	195.00
36	NUMBER OF SUBSTATIONS DIST UNATTENDED - 181				
37					
38	ALBINA	T/D-UNATTENDED	115.00	12.47	69.00
39	APPLEGATE	T/D-UNATTENDED	115.00	69.00	12.47
40	ASHLAND	T/D-UNATTENDED	115.00	69.00	12.47

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
9	1					1
20	1					2
7	3					3
40	2					4
55	2					5
	1					6
25	1					7
13	1					8
42	2					9
13	1					10
50	2					11
17	6					12
1	1					13
11	1					14
13	1					15
25	2					16
13	2					17
50	2					18
25	1					19
40	2					20
22	4					21
7	1					22
13	3					23
25	2					24
3	3					25
3	1					26
50	2					27
22	2					28
23	9					29
40	2					30
60	3					31
28	3					32
23	3					33
37	2					34
4409	365	5				35
						36
						37
177	9					38
65	2					39
70	2					40

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS

- Report below the information called for concerning substations of the respondent as of the end of the year.
- Substations which serve only one industrial or street railway customer should not be listed below.
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- 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	BEND PLANT	T/D-UNATTENDED	69.00	4.16	12.47
2	CAVE JUNCTION	T/D-UNATTENDED	115.00	12.47	69.00
3	HAZELWOOD	T/D-UNATTENDED	115.00	69.00	12.47
4	KNOTT	T/D-UNATTENDED	115.00	12.47	57.00
5	MILE HI	T/D-UNATTENDED	115.00	69.00	12.47
6	PILOT BUTTE	T/D-UNATTENDED	230.00	69.00	12.47
7	WINCHESTER	T/D-UNATTENDED	115.00	12.47	69.00
8	Total		1219.00	399.04	338.82
9	NUMBER OF SUBSTATIONS T/D UNATTENDED - 10				
10					
11	CLEARWATER #1 HYDRO PLANT	TRANSMISSION-ATTEND	138.00	6.90	
12	CLEARWATER #2 HYDRO PLANT	TRANSMISSION-ATTEND	138.00	12.00	
13	FISH CREEK HYDRO	TRANSMISSION-ATTEND	115.00	6.90	
14	JC BOYLE HYDRO	TRANSMISSION-ATTEND	230.00	11.00	
15	LEMOLO #1 HYDRO	TRANSMISSION-ATTEND	115.00	12.47	
16	LEMOLO #2 HYDRO	TRANSMISSION-ATTEND	115.00	12.00	
17	PROSPECT 1 HYDRO	TRANSMISSION-ATTEND	69.00	2.30	
18	PROSPECT 2 HYDRO	TRANSMISSION-ATTEND	69.00	6.60	
19	PROSPECT 3 HYDRO	TRANSMISSION-ATTEND	69.00	12.47	
20	TOKETEE HYDRO	TRANSMISSION-ATTEND	115.00	6.90	
21	Total		1173.00	89.54	
22	NUMBER OF SUBSTATIONS TRANS ATTENDED - 10				
23					
24	BEND PLANT	TRANSMISSION-UNATTEN	4.16	2.40	
25	CALAPOOYA	TRANSMISSION-UNATTEN	230.00	69.00	
26	CHILOQUIN	TRANSMISSION-UNATTEN	230.00	115.00	69.00
27	COLD SPRINGS	TRANSMISSION-UNATTEN	230.00	69.00	
28	COVE	TRANSMISSION-UNATTEN	230.00	69.00	
29	DAYS CREEK	TRANSMISSION-UNATTEN	115.00	69.00	
30	DIAMOND HILL	TRANSMISSION-UNATTEN	230.00	69.00	
31	DIXONVILLE 115/230	TRANSMISSION-UNATTEN	230.00	115.00	69.00
32	DIXONVILLE 500	TRANSMISSION-UNATTEN	500.00	230.00	
33	EAGLE POINT HYDRO	TRANSMISSION-UNATTEN	115.00	2.40	
34	EAST SIDE HYDRO	TRANSMISSION-UNATTEN	46.00	12.47	
35	FISH HOLE	TRANSMISSION-UNATTEN	115.00	69.00	
36	FRY	TRANSMISSION-UNATTEN	230.00	115.00	
37	GRANTS PASS	TRANSMISSION-UNATTEN	230.00	115.00	69.00
38	GREEN SPRINGS PLANT	TRANSMISSION-UNATTEN	115.00	69.00	
39	HURRICANE	TRANSMISSION-UNATTEN	230.00	69.00	2.40
40	ISTHMUS	TRANSMISSION-UNATTEN	230.00	115.00	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
23	3					1
70	2					2
132	4					3
187	8					4
39	4					5
400	4					6
75	5					7
1238	43					8
						9
						10
17	3					11
31	3					12
13	3					13
89	2	1				14
48	7	1				15
40	4					16
5	3					17
40	6	1				18
10	6					19
50	9					20
343	46	3				21
						22
						23
3	3					24
75	1					25
119	4					26
60	1					27
67	3					28
50	1					29
75	1					30
344	6					31
650	3	1				32
3	1					33
3	3					34
7	3					35
500	2					36
458	4					37
19	3					38
29	2					39
250	1					40

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	KENNEDY	TRANSMISSION-UNATTEN	69.00	57.00	
2	KLAMATH FALLS	TRANSMISSION-UNATTEN	230.00	69.00	
3	LONE PINE	TRANSMISSION-UNATTEN	230.00	115.00	69.00
4	MERIDIAN	TRANSMISSION-UNATTEN	500.00	230.00	
5	MONPAC	TRANSMISSION-UNATTEN	115.00	69.00	
6	PONDEROSA	TRANSMISSION-UNATTEN	230.00	115.00	
7	POWERDALE PLANT	TRANSMISSION-UNATTEN	69.00	7.20	
8	PROSPECT CENTRAL	TRANSMISSION-UNATTEN	115.00	69.00	
9	ROBERTS CREEK	TRANSMISSION-UNATTEN	115.00	69.00	
10	SLIDE CREEK HYDRO	TRANSMISSION-UNATTEN	115.00	7.00	
11	SODA SPRINGS HYDRO	TRANSMISSION-UNATTEN	115.00	7.00	
12	TROUTDALE	TRANSMISSION-UNATTEN	230.00	115.00	69.00
13	TUCKER	TRANSMISSION-UNATTEN	115.00	69.00	
14	WALLOWA FALLS HYDRO	TRANSMISSION-UNATTEN	20.80		
15	Total		5578.96	2372.47	347.40
16	NUMBER OF SUBSTATIONS TRANS UNATTEND - 31				
17					
18	Utah				
19	106TH SOUTH	DISTRIBUTION-UNATTEN	138.00	12.50	
20	118TH SOUTH	DISTRIBUTION-UNATTEN	138.00	12.47	
21	70TH SOUTH	DISTRIBUTION-UNATTEN	138.00	12.47	
22	ALTAVIEW	DISTRIBUTION-UNATTEN	46.00	12.47	
23	AMALGA	DISTRIBUTION-UNATTEN	46.00	12.47	
24	AMERICAN FORK	DISTRIBUTION-UNATTEN	138.00	12.47	
25	ARAGONITE	DISTRIBUTION-UNATTEN	46.00	7.20	
26	AURORA	DISTRIBUTION-UNATTEN	46.00	12.47	
27	BANGERTER	DISTRIBUTION-UNATTEN	138.00	12.47	
28	BEAR RIVER	DISTRIBUTION-UNATTEN	46.00	12.47	
29	BENJAMIN	DISTRIBUTION-UNATTEN	46.00	12.47	
30	BINGHAM	DISTRIBUTION-UNATTEN	46.00	12.47	
31	BLUE CREEK	DISTRIBUTION-UNATTEN	46.00	12.47	
32	BLUFF	DISTRIBUTION-UNATTEN	69.00	12.47	
33	BLUFFDALE	DISTRIBUTION-UNATTEN	46.00	12.47	
34	BOTHWELL	DISTRIBUTION-UNATTEN	46.00	12.47	
35	BOX ELDER	DISTRIBUTION-UNATTEN	46.00	12.47	
36	BRIAN HEAD	DISTRIBUTION-UNATTEN	46.00	12.47	
37	BRICKYARD	DISTRIBUTION-UNATTEN	46.00	12.47	
38	BRIGHTON	DISTRIBUTION-UNATTEN	46.00	24.90	
39	BROOKLAWN	DISTRIBUTION-UNATTEN	46.00	12.47	
40	BRUNSWICK	DISTRIBUTION-UNATTEN	46.00	12.47	

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SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
33	1					1
251	6	1				2
733	10					3
1300	6	1				4
50	1					5
250	1					6
8	3	1				7
47	4					8
50	1					9
21	3					10
13	3					11
500	3					12
100	2					13
2	3					14
6070	89	4				15
						16
						17
						18
30	1					19
30	1					20
	1					21
45	2					22
11	1					23
30	1					24
1	1					25
3	1					26
50	1					27
17	2					28
2	1					29
11	1					30
2	3					31
1	3					32
9	1					33
4	1					34
14	1					35
14	1					36
9	1					37
26	2					38
6	1					39
60	3					40

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	BURTON	DISTRIBUTION-UNATTEN	34.50	12.47	
2	BUSH	DISTRIBUTION-UNATTEN	46.00	12.47	
3	CANNON	DISTRIBUTION-UNATTEN	46.00	12.47	
4	CANYONLANDS	DISTRIBUTION-UNATTEN	69.00	12.47	
5	CAPITOL	DISTRIBUTION-UNATTEN	46.00	12.47	
6	CARBIDE	DISTRIBUTION-UNATTEN	46.00	7.20	
7	CARBONVILLE	DISTRIBUTION-UNATTEN	46.00	12.47	
8	CARLISLE	DISTRIBUTION-UNATTEN	138.00	12.50	
9	CASTO SUBSTATION	DISTRIBUTION-UNATTEN	46.00	12.47	
10	CENTENNIAL	DISTRIBUTION-UNATTEN	138.00	12.47	
11	CENTERVILLE	DISTRIBUTION-UNATTEN	46.00	12.47	
12	CENTRAL	DISTRIBUTION-UNATTEN	46.00	12.47	
13	CHAPEL HILL	DISTRIBUTION-UNATTEN	138.00	12.47	
14	CHERRYWOOD	DISTRIBUTION-UNATTEN	138.00	12.47	
15	CIRCLEVILLE	DISTRIBUTION-UNATTEN	69.00	12.47	
16	CLEAR CREEK	DISTRIBUTION-UNATTEN	46.00	12.47	
17	CLEAR LAKE	DISTRIBUTION-UNATTEN	46.00	12.47	
18	CLEARFIELD SOUTH	DISTRIBUTION-UNATTEN	138.00	12.47	
19	CLINTON	DISTRIBUTION-UNATTEN	138.00	12.47	
20	CLIVE	DISTRIBUTION-UNATTEN	46.00	12.47	
21	COALVILLE	DISTRIBUTION-UNATTEN	46.00	12.47	
22	COLD WATER CANYON	DISTRIBUTION-UNATTEN	138.00	12.47	
23	COLEMAN	DISTRIBUTION-UNATTEN	138.00	69.00	12.47
24	COLTON WELL	DISTRIBUTION-UNATTEN	46.00	12.47	
25	CORINNE	DISTRIBUTION-UNATTEN	46.00	12.47	
26	COVE FORT	DISTRIBUTION-UNATTEN	46.00	12.47	
27	CRESCENT JUNCTION	DISTRIBUTION-UNATTEN	46.00	7.20	
28	CROSS HOLLOW	DISTRIBUTION-UNATTEN	138.00	12.47	
29	CUDAHY	DISTRIBUTION-UNATTEN	138.00	12.47	
30	DAMMERON VALLEY	DISTRIBUTION-UNATTEN	34.50	12.47	
31	DECKER LAKE	DISTRIBUTION-UNATTEN	138.00	12.47	
32	DELLE	DISTRIBUTION-UNATTEN	46.00	12.47	
33	DELTA	DISTRIBUTION-UNATTEN	46.00	12.47	
34	DESERET	DISTRIBUTION-UNATTEN	46.00	4.16	
35	DEWEYVILLE	DISTRIBUTION-UNATTEN	46.00	12.47	
36	DIMPLE DELL	DISTRIBUTION-UNATTEN	138.00	12.47	
37	DIXIE DEER	DISTRIBUTION-UNATTEN	34.50	12.47	
38	DRAPER	DISTRIBUTION-UNATTEN	46.00	12.47	
39	DUMAS	DISTRIBUTION-UNATTEN	138.00	12.47	
40	EAST BENCH	DISTRIBUTION-UNATTEN	138.00	12.47	

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SUBSTATIONS (Continued)

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

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Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
4	1					1
9	1					2
13	1					3
1	1					4
20	1					5
3	1					6
6	1					7
30	1					8
25	1					9
40	2					10
22	1					11
2	1					12
30	1					13
25	1					14
3	1					15
4	1					16
	3					17
60	2					18
50	2					19
4	1					20
20	2					21
30	1					22
106	4					23
1	3					24
3	1					25
2	3					26
1	1					27
22	1					28
22	1					29
42	1					30
55	2					31
6	1					32
23	2					33
2	1					34
4	1					35
60	2					36
2	1					37
23	2					38
60	2					39
30	1					40

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	EAST HYRUM	DISTRIBUTION-UNATTEN	46.00	12.47	
2	EAST LAYTON	DISTRIBUTION-UNATTEN	138.00	12.47	
3	EAST MILLCREEK	DISTRIBUTION-UNATTEN	46.00	12.47	
4	EDEN	DISTRIBUTION-UNATTEN	46.00	12.47	
5	ELBERTA	DISTRIBUTION-UNATTEN	46.00	12.47	
6	ELK MEADOWS	DISTRIBUTION-UNATTEN	46.00	12.47	
7	ELSINORE	DISTRIBUTION-UNATTEN	46.00	12.47	
8	EMERY CITY	DISTRIBUTION-UNATTEN	69.00	12.47	
9	EMIGRATION	DISTRIBUTION-UNATTEN	46.00	12.47	
10	ENOCH	DISTRIBUTION-UNATTEN	138.00	12.47	
11	ENTERPRISE VALLEY	DISTRIBUTION-UNATTEN	138.00	12.47	
12	EUREKA	DISTRIBUTION-UNATTEN	46.00	12.47	
13	FARMINGTON	DISTRIBUTION-UNATTEN	138.00	12.47	
14	FAYETTE	DISTRIBUTION-UNATTEN	46.00	12.47	
15	FERRON	DISTRIBUTION-UNATTEN	46.00	12.47	
16	FIELDING	DISTRIBUTION-UNATTEN	46.00	12.00	
17	FIFTH WEST	DISTRIBUTION-UNATTEN	138.00	12.47	
18	FLUX	DISTRIBUTION-UNATTEN	46.00	12.47	
19	FOOL CREEK	DISTRIBUTION-UNATTEN	46.00	12.47	
20	FOUNTAIN GREEN	DISTRIBUTION-UNATTEN	46.00	12.47	
21	FREEDOM	DISTRIBUTION-UNATTEN	46.00	7.20	
22	FRUIT HEIGHTS	DISTRIBUTION-UNATTEN	46.00	12.47	
23	GARDEN CITY	DISTRIBUTION-UNATTEN	46.00	12.47	
24	GATEWAY	DISTRIBUTION-UNATTEN	69.00	12.47	
25	GORDON AVENUE	DISTRIBUTION-UNATTEN	138.00	12.50	
26	GOSHEN	DISTRIBUTION-UNATTEN	46.00	12.47	
27	GRANGER	DISTRIBUTION-UNATTEN	46.00	12.47	
28	GRANTSVILLE	DISTRIBUTION-UNATTEN	46.00	12.47	
29	GREEN RIVER	DISTRIBUTION-UNATTEN	46.00	12.47	
30	GROW	DISTRIBUTION-UNATTEN	138.00	12.47	46.00
31	GUNLOCK HYDRO	DISTRIBUTION-UNATTEN	34.50	2.30	
32	GUNNISON	DISTRIBUTION-UNATTEN	46.00	12.47	
33	HAMILTON	DISTRIBUTION-UNATTEN	34.50	12.47	
34	HAMMER	DISTRIBUTION-UNATTEN	138.00	12.47	
35	HAVASU	DISTRIBUTION-UNATTEN	69.00	12.47	
36	HELPER CITY	DISTRIBUTION-UNATTEN	46.00	4.16	
37	HENEFER	DISTRIBUTION-UNATTEN	46.00	12.47	
38	HIAWATHA	DISTRIBUTION-UNATTEN	46.00	4.16	
39	HIGHLAND DIST	DISTRIBUTION-UNATTEN	46.00	12.47	
40	HOGGARD	DISTRIBUTION-UNATTEN	138.00	12.47	

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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
6	1					1
30	1					2
20	1					3
12	2					4
5	1					5
3	1					6
2	1					7
3	3					8
25	1					9
14	1					10
10	1					11
3	1					12
30	1					13
1	2					14
5	1					15
6	1					16
30	1					17
4	1					18
2	1					19
2	1					20
	1					21
22	1					22
6	1					23
28	2	1				24
30	1					25
2	1					26
43	2					27
10	1					28
5	2					29
72	3					30
1	1					31
11	1					32
1	3					33
60	2					34
3	1					35
3	3					36
1	3					37
1	3					38
25	1					39
50	2					40

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	HOGLE	DISTRIBUTION-UNATTEN	46.00	12.47	
2	HOLDEN	DISTRIBUTION-UNATTEN	46.00	12.47	
3	HOLLADAY	DISTRIBUTION-UNATTEN	46.00	12.47	
4	HUNTER	DISTRIBUTION-UNATTEN	46.00	12.47	
5	HUNTINGTON CITY	DISTRIBUTION-UNATTEN	69.00	12.47	
6	HURRICANE FIELDS	DISTRIBUTION-UNATTEN	34.50	12.47	
7	IRON MOUNTAIN	DISTRIBUTION-UNATTEN	34.50	7.20	
8	IRON SPRINGS	DISTRIBUTION-UNATTEN	34.50	12.47	
9	IRONTON	DISTRIBUTION-UNATTEN	46.00	12.47	
10	IVINS	DISTRIBUTION-UNATTEN	34.50	12.47	
11	JORDAN NARROWS	DISTRIBUTION-UNATTEN	46.00	2.40	
12	JORDAN PARK	DISTRIBUTION-UNATTEN	138.00	12.47	
13	JORDANELLE	DISTRIBUTION-UNATTEN	138.00	12.47	
14	JUAB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	JUNCTION	DISTRIBUTION-UNATTEN	69.00	12.47	
16	KAIBAB	DISTRIBUTION-UNATTEN	69.00	12.47	
17	KAMAS	DISTRIBUTION-UNATTEN	46.00	12.47	
18	KANARRAVILLE	DISTRIBUTION-UNATTEN	34.50	12.47	
19	KEARNS	DISTRIBUTION-UNATTEN	138.00	12.47	
20	KENSINGTON	DISTRIBUTION-UNATTEN	46.00	4.16	
21	LAKE PARK	DISTRIBUTION-UNATTEN	138.00	12.47	
22	LARK	DISTRIBUTION-UNATTEN	46.00	12.47	
23	LASAL	DISTRIBUTION-UNATTEN	69.00	12.47	
24	LAYTON	DISTRIBUTION-UNATTEN	46.00	12.47	
25	LEGRANDE	DISTRIBUTION-UNATTEN	46.00	12.47	
26	LEWISTON	DISTRIBUTION-UNATTEN	46.00	12.47	
27	LINCOLN	DISTRIBUTION-UNATTEN	46.00	12.47	
28	LINDON	DISTRIBUTION-UNATTEN	46.00	12.47	
29	LISBON	DISTRIBUTION-UNATTEN	69.00	12.47	
30	LITTLE MOUNTAIN	DISTRIBUTION-UNATTEN	46.00	12.47	
31	LOAFER	DISTRIBUTION-UNATTEN	46.00	12.47	
32	LOGAN CANYON	DISTRIBUTION-UNATTEN	46.00	7.20	
33	LONE TREE	DISTRIBUTION-UNATTEN	34.50	12.47	
34	LOWER BEAVER	DISTRIBUTION-UNATTEN	46.00	6.60	
35	LYNN DYLL	DISTRIBUTION-UNATTEN	46.00	12.47	
36	MAESER	DISTRIBUTION-UNATTEN	69.00	12.47	
37	MAGNA	DISTRIBUTION-UNATTEN	138.00	12.47	
38	MANILA	DISTRIBUTION-UNATTEN	46.00	12.47	
39	MANTUA	DISTRIBUTION-UNATTEN	46.00	12.47	
40	MAPLETON	DISTRIBUTION-UNATTEN	46.00	12.47	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
22	1					1
4	1					2
32	2					3
22	1					4
13	2					5
1	3					6
1	1					7
5	3					8
2	1					9
22	1					10
13	2					11
30	1					12
30	1					13
2	3					14
3	1					15
5	1					16
7	1					17
1	3					18
60	2					19
7	1					20
53	2					21
6	1					22
5	1					23
40	2					24
2	1					25
14	1					26
20	1					27
20	1					28
4	1					29
20	1					30
	1					31
	1					32
20	1					33
1	3					34
4	1					35
13	1					36
30	1					37
22	1					38
2	1					39
14	1					40

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	MARRIOTT	DISTRIBUTION-UNATTEN	46.00	12.47	
2	MARYSVALE	DISTRIBUTION-UNATTEN	46.00	12.47	
3	MATHIS	DISTRIBUTION-UNATTEN	46.00	12.47	
4	MCCORNICK	DISTRIBUTION-UNATTEN	46.00	12.47	
5	MCKAY	DISTRIBUTION-UNATTEN	46.00	12.47	
6	MEADOWBROOK	DISTRIBUTION-UNATTEN	138.00	12.47	46.00
7	MEDICAL	DISTRIBUTION-UNATTEN	46.00	12.47	
8	MELLING	DISTRIBUTION-UNATTEN	34.50	4.16	
9	MIDLAND	DISTRIBUTION-UNATTEN	138.00	12.47	
10	MIDVALE	DISTRIBUTION-UNATTEN	46.00	12.47	
11	MILFORD	DISTRIBUTION-UNATTEN	46.00	12.47	
12	MILFORD TV	DISTRIBUTION-UNATTEN	46.00	7.20	
13	MILLVILLE	DISTRIBUTION-UNATTEN	46.00	12.47	
14	MINERSVILLE	DISTRIBUTION-UNATTEN	46.00	12.47	
15	MOAB CITY	DISTRIBUTION-UNATTEN	69.00	12.47	
16	MONTEZUMA	DISTRIBUTION-UNATTEN	69.00	12.47	
17	MOORE	DISTRIBUTION-UNATTEN	69.00	12.47	
18	MORGAN	DISTRIBUTION-UNATTEN	46.00	4.16	
19	MORONI	DISTRIBUTION-UNATTEN	46.00	12.47	
20	MORTON COURT	DISTRIBUTION-UNATTEN	138.00	12.47	
21	MOSS JUNCTION	DISTRIBUTION-UNATTEN	46.00	12.47	
22	MOUNTAIN DELL	DISTRIBUTION-UNATTEN	46.00	12.47	
23	MOUNTAIN GREEN	DISTRIBUTION-UNATTEN	46.00	12.47	
24	MYTON	DISTRIBUTION-UNATTEN	69.00	12.47	
25	NEW HARMONY	DISTRIBUTION-UNATTEN	69.00	12.47	
26	NEWGATE	DISTRIBUTION-UNATTEN	46.00	12.47	
27	NEWTON	DISTRIBUTION-UNATTEN	46.00	12.47	
28	NIBLEY	DISTRIBUTION-UNATTEN	46.00	24.90	
29	NORTH BENCH	DISTRIBUTION-UNATTEN	46.00	12.47	
30	NORTH CEDAR	DISTRIBUTION-UNATTEN	34.50	4.16	
31	NORTH FIELDS	DISTRIBUTION-UNATTEN	46.00	12.47	
32	NORTH LOGAN	DISTRIBUTION-UNATTEN	46.00	12.47	
33	NORTH OGDEN	DISTRIBUTION-UNATTEN	46.00	12.47	
34	NORTH SALT LAKE	DISTRIBUTION-UNATTEN	46.00	12.47	
35	NORTHEAST	DISTRIBUTION-UNATTEN	46.00	12.47	
36	NORTHRIDGE	DISTRIBUTION-UNATTEN	46.00	12.47	
37	OAKLAND AVE	DISTRIBUTION-UNATTEN	46.00	12.47	
38	OAKLEY	DISTRIBUTION-UNATTEN	46.00	12.47	
39	OGDEN DEFENSE DEPOT	DISTRIBUTION-UNATTEN	46.00	12.47	
40	OLYMPUS	DISTRIBUTION-UNATTEN	46.00	12.47	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
20	1					1
2	3					2
9	1					3
6	1					4
20	1					5
42	2					6
58	4					7
5	1					8
30	1					9
25	1					10
14	1					11
1	1					12
13	1					13
2	1					14
19	2					15
13	1					16
3	1					17
3	1					18
6	1					19
25	1					20
6	3					21
5	1					22
6	1					23
6	1					24
7	1					25
20	1					26
5	1					27
14	1					28
25	1					29
5	1					30
2	1					31
25	1					32
22	1					33
13	1					34
45	10					35
14	1					36
24	2					37
6	1					38
11	5	3				39
22	1					40

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	OPHIR	DISTRIBUTION-UNATTEN	46.00	12.47	
2	ORANGE	DISTRIBUTION-UNATTEN	46.00	12.47	
3	ORANGEVILLE	DISTRIBUTION-UNATTEN	69.00	12.47	
4	OREM	DISTRIBUTION-UNATTEN	46.00	12.47	
5	OREMET	DISTRIBUTION-UNATTEN	115.00	12.47	
6	PACK CREEK RESERVOIR	DISTRIBUTION-UNATTEN	46.00	12.47	
7	PANGUITCH	DISTRIBUTION-UNATTEN	69.00	12.47	
8	PARIETTE STATION	DISTRIBUTION-UNATTEN	69.00	24.90	
9	PARK CITY	DISTRIBUTION-UNATTEN	46.00	12.47	
10	PARKWAY	DISTRIBUTION-UNATTEN	138.00	12.47	
11	PARLEYS	DISTRIBUTION-UNATTEN	46.00	12.47	
12	PELICAN POINT	DISTRIBUTION-UNATTEN	46.00	12.47	
13	PINE CANYON	DISTRIBUTION-UNATTEN	138.00	12.47	
14	PINE CREEK	DISTRIBUTION-UNATTEN	46.00	12.47	
15	PINNACLE	DISTRIBUTION-UNATTEN	46.00	12.47	
16	PLAIN CITY	DISTRIBUTION-UNATTEN	138.00	12.47	
17	PLEASANT GROVE	DISTRIBUTION-UNATTEN	46.00	12.47	
18	PLEASANT VIEW	DISTRIBUTION-UNATTEN	46.00	12.47	
19	PORTER ROCKWELL	DISTRIBUTION-UNATTEN	138.00	12.47	
20	PROMONTORY	DISTRIBUTION-UNATTEN	46.00	12.47	
21	QUAIL CREEK	DISTRIBUTION-UNATTEN	34.50	12.47	
22	QUARRY	DISTRIBUTION-UNATTEN	138.00	12.47	
23	QUITCHAPA	DISTRIBUTION-UNATTEN	34.50	12.47	
24	RAINS	DISTRIBUTION-UNATTEN	46.00	7.20	
25	RANDOLPH	DISTRIBUTION-UNATTEN	46.00	12.47	
26	RASMUSON	DISTRIBUTION-UNATTEN	46.00	12.47	
27	RATTLESNAKE	DISTRIBUTION-UNATTEN	69.00	24.90	
28	RED MOUNTAIN	DISTRIBUTION-UNATTEN	69.00	34.50	
29	RED ROCK	DISTRIBUTION-UNATTEN	69.00	4.16	
30	REDWOOD	DISTRIBUTION-UNATTEN	46.00	12.47	
31	RESEARCH PARK	DISTRIBUTION-UNATTEN	46.00	12.47	
32	RICH	DISTRIBUTION-UNATTEN	69.00	12.47	
33	RICHFIELD	DISTRIBUTION-UNATTEN	46.00	12.47	
34	RICHMOND	DISTRIBUTION-UNATTEN	46.00	12.47	
35	RIDGELAND	DISTRIBUTION-UNATTEN	138.00	12.47	
36	RITER	DISTRIBUTION-UNATTEN	46.00	12.47	
37	ROCK CANYON	DISTRIBUTION-UNATTEN	69.00	12.47	
38	ROCKVILLE	DISTRIBUTION-UNATTEN	34.50	12.47	
39	ROCKY POINT	DISTRIBUTION-UNATTEN	138.00	13.20	
40	ROSE PARK	DISTRIBUTION-UNATTEN	46.00	12.47	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
3	1					1
20	1					2
14	1					3
48	2					4
55	2					5
4	1					6
5	1					7
4	3					8
35	2					9
50	2					10
16	2					11
6	1					12
20	1					13
2	1					14
14	1					15
22	1					16
25	1					17
14	1					18
30	1					19
2	1					20
4	1					21
60	2					22
4	1					23
15	1					24
2	1					25
1	3					26
14	1					27
13	1					28
3	1					29
45	2					30
45	2					31
5	1					32
22	2					33
11	1					34
40	2					35
20	1					36
5	1					37
4	1					38
30	1					39
24	3					40

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	ROYAL	DISTRIBUTION-UNATTEN	46.00	4.16	
2	SALINA	DISTRIBUTION-UNATTEN	46.00	12.47	
3	SANDY	DISTRIBUTION-UNATTEN	138.00	12.47	
4	SARATOGA	DISTRIBUTION-UNATTEN	138.00	12.47	
5	SCIPIO	DISTRIBUTION-UNATTEN	46.00	12.47	
6	SCOFIELD RESERVOIR	DISTRIBUTION-UNATTEN	46.00	7.20	
7	SCOFIELD	DISTRIBUTION-UNATTEN	46.00	12.47	
8	SECOND STREET	DISTRIBUTION-UNATTEN	46.00	12.47	
9	SEVEN MILE	DISTRIBUTION-UNATTEN	46.00	12.47	
10	SHARON	DISTRIBUTION-UNATTEN	46.00	12.47	
11	SHIVWITS	DISTRIBUTION-UNATTEN	34.50	4.16	
12	SIXTH SOUTH	DISTRIBUTION-UNATTEN	46.00	12.47	
13	SKULL POINT	DISTRIBUTION-UNATTEN	46.00	12.47	
14	SNARR	DISTRIBUTION-UNATTEN	46.00	12.47	
15	SNOWVILLE	DISTRIBUTION-UNATTEN	69.00	12.47	
16	SNYDERVILLE	DISTRIBUTION-UNATTEN	138.00	12.47	
17	SOLDIER SUMMIT	DISTRIBUTION-UNATTEN	69.00	12.47	
18	SOUTH JORDAN	DISTRIBUTION-UNATTEN	138.00	12.47	
19	SOUTH MILFORD	DISTRIBUTION-UNATTEN	46.00	12.47	
20	SOUTH MOUNTAIN	DISTRIBUTION-UNATTEN	138.00	12.47	
21	SOUTH OGDEN	DISTRIBUTION-UNATTEN	46.00	12.47	
22	SOUTH PARK	DISTRIBUTION-UNATTEN	46.00	12.47	
23	SOUTH WEBER	DISTRIBUTION-UNATTEN	138.00	12.47	
24	SOUTHEAST	DISTRIBUTION-UNATTEN	138.00	12.47	46.00
25	SOUTHWEST	DISTRIBUTION-UNATTEN	46.00	12.47	
26	SPANISH VALLEY	DISTRIBUTION-UNATTEN	69.00	12.47	
27	SPRINGDALE	DISTRIBUTION-UNATTEN	34.50	12.47	
28	ST. JOHNS	DISTRIBUTION-UNATTEN	46.00	12.47	
29	STAIRS	DISTRIBUTION-UNATTEN	12.47	2.40	
30	STANSBURY	DISTRIBUTION-UNATTEN	46.00	12.47	
31	SUMMIT CREEK	DISTRIBUTION-UNATTEN	138.00	12.47	
32	SUMMIT PARK	DISTRIBUTION-UNATTEN	46.00	12.47	
33	SUNRISE	DISTRIBUTION-UNATTEN	138.00	12.47	
34	SUPERIOR	DISTRIBUTION-UNATTEN	69.00	12.47	
35	SUTHERLAND	DISTRIBUTION-UNATTEN	46.00	12.47	
36	TAYLOR	DISTRIBUTION-UNATTEN	46.00	12.47	
37	THIEF CREEK	DISTRIBUTION-UNATTEN	138.00	24.90	
38	THIRD WEST	DISTRIBUTION-UNATTEN	46.00	12.47	
39	THIRTEENTH SOUTH	DISTRIBUTION-UNATTEN	46.00	12.47	
40	THOMPSON	DISTRIBUTION-UNATTEN	46.00	4.16	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
	3					1
11	1					2
60	2					3
30	1					4
1	3					5
	1					6
1	3					7
13	2					8
5	3					9
20	1					10
6	1					11
20	1					12
2	1					13
40	2					14
5	1					15
30	1					16
13	1					17
30	1					18
20	2					19
60	2					20
25	1					21
14	1					22
50	1					23
50	2					24
22	2					25
6	1					26
4	1					27
4	1					28
2	1					29
20	1					30
14	1					31
7	1					32
30	1					33
8	1					34
6	1					35
14	1					36
14	1					37
40	2					38
24	3					39
2	1					40

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4	
SUBSTATIONS						
<p>1. Report below the information called for concerning substations of the respondent as of the end of the year.</p> <p>2. Substations which serve only one industrial or street railway customer should not be listed below.</p> <p>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.</p> <p>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).</p>						
Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)			
			Primary (c)	Secondary (d)	Tertiary (e)	
1	TOOELE DEPOT	DISTRIBUTION-UNATTEN	46.00	12.50		
2	TOQUERVILLE	DISTRIBUTION-UNATTEN	69.00	12.47	34.50	
3	TRI CITY	DISTRIBUTION-UNATTEN	138.00	12.47		
4	TWENTYTHIRD STREET	DISTRIBUTION-UNATTEN	46.00	12.47		
5	UINTAH	DISTRIBUTION-UNATTEN	46.00	12.47		
6	UNION	DISTRIBUTION-UNATTEN	46.00	12.47		
7	UNIVERSITY	DISTRIBUTION-UNATTEN	46.00	4.16		
8	VALLEY CENTER	DISTRIBUTION-UNATTEN	46.00	12.47		
9	VERMILLION	DISTRIBUTION-UNATTEN	46.00	12.47		
10	VERNAL	DISTRIBUTION-UNATTEN	69.00	12.47		
11	VEYO HYDRO	DISTRIBUTION-UNATTEN	34.50	2.40		
12	VICKERS	DISTRIBUTION-UNATTEN	46.00	12.47		
13	VINEYARD	DISTRIBUTION-UNATTEN	46.00	12.47		
14	WALFARE	DISTRIBUTION-UNATTEN	46.00	12.47		
15	WALLSBURG	DISTRIBUTION-UNATTEN	138.00	12.47		
16	WALNUT GROVE	DISTRIBUTION-UNATTEN	138.00	12.50		
17	WARREN	DISTRIBUTION-UNATTEN	138.00	12.47		
18	WASATCH STATE PARK	DISTRIBUTION-UNATTEN	46.00	12.47		
19	WASHAKIE	DISTRIBUTION-UNATTEN	138.00	4.16		
20	WELBY	DISTRIBUTION-UNATTEN	46.00	12.47		
21	WELLINGTON	DISTRIBUTION-UNATTEN	46.00	12.47		
22	WEST COMMERCIAL	DISTRIBUTION-UNATTEN	46.00	12.47		
23	WEST JORDAN	DISTRIBUTION-UNATTEN	138.00	12.47		
24	WEST OGDEN	DISTRIBUTION-UNATTEN	138.00	12.47		
25	WEST ROY	DISTRIBUTION-UNATTEN	46.00	12.47		
26	WEST TEMPLE	DISTRIBUTION-UNATTEN	46.00	4.16		
27	WESTFIELD	DISTRIBUTION-UNATTEN	138.00	12.47		
28	WESTWATER	DISTRIBUTION-UNATTEN	69.00	12.47		
29	WHITE MESA	DISTRIBUTION-UNATTEN	69.00	12.47		
30	WILLOWCREEK	DISTRIBUTION-UNATTEN	46.00	12.47		
31	WILLOWRIDGE	DISTRIBUTION-UNATTEN	46.00	12.47		
32	WINCHESTER HILLS	DISTRIBUTION-UNATTEN	34.50	12.47		
33	WINKLEMAN	DISTRIBUTION-UNATTEN	46.00	7.20		
34	WOLF CREEK	DISTRIBUTION-UNATTEN	69.00	12.47		
35	WOOD CROSS	DISTRIBUTION-UNATTEN	46.00	12.47		
36	WOODRUFF	DISTRIBUTION-UNATTEN	46.00	12.47		
37	Total		19907.47	3641.89	184.97	
38	NUMBER OF SUBSTATIONS DIST UNATTENDED - 298					
39						
40	ANGEL	T/D-UNATTENDED	138.00	12.47	46.00	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
14	1					1
34	2					2
30	1					3
13	1					4
39	2					5
50	2					6
48	4					7
22	1					8
3	1					9
33	2					10
2	3					11
2	1					12
25	1					13
5	1					14
13	1					15
30	1					16
30	1					17
2	3					18
14	1					19
22	1					20
4	1					21
22	1					22
28	1					23
30	1					24
25	1					25
60	3					26
20	1					27
1	3					28
14	1					29
6	1					30
14	1					31
4	1					32
	1					33
6	1					34
20	1					35
2	1					36
5164	432	4				37
						38
						39
135	3					40

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	BDO	T/D-UNATTENDED	138.00	12.47	
2	BUTLERVILLE	T/D-UNATTENDED	138.00	46.00	12.47
3	COTTONWOOD	T/D-UNATTENDED	138.00	12.47	46.00
4	EMMA PARK	T/D-UNATTENDED	138.00	12.47	
5	HALE	T/D-UNATTENDED	138.00	46.00	12.47
6	HIGHLAND	T/D-UNATTENDED	138.00	12.47	46.00
7	JORDAN	T/D-UNATTENDED	138.00	46.00	12.47
8	JUDGE	T/D-UNATTENDED	46.00	12.47	
9	MCCLELLAND	T/D-UNATTENDED	138.00	46.00	12.47
10	OQUIRRH	T/D-UNATTENDED	138.00	46.00	12.47
11	PARRISH	T/D-UNATTENDED	138.00	12.47	46.00
12	PIONEER PLANT	T/D-UNATTENDED	138.00	2.30	46.00
13	RIVERDALE	T/D-UNATTENDED	138.00	46.00	12.47
14	SEVIER	T/D-UNATTENDED	138.00	46.00	12.47
15	SILVER CREEK	T/D-UNATTENDED	138.00	12.47	46.00
16	SPHINX	T/D-UNATTENDED	46.00	12.47	
17	SYRACUSE	T/D-UNATTENDED	138.00	46.00	12.47
18	TAYLORSVILLE	T/D-UNATTENDED	138.00	46.00	12.47
19	TERMINAL	T/D-UNATTENDED	345.00	12.47	46.00
20	TIMP	T/D-UNATTENDED	138.00	46.00	12.47
21	TOOELE	T/D-UNATTENDED	138.00	46.00	12.47
22	WEST VALLEY	T/D-UNATTENDED	138.00	12.47	
23	Total		3197.00	645.47	459.17
24	NUMBER OF SUBSTATIONS T/D UNATTENDED - 23				
25					
26	BLUNDELL PLANT	TRANSMISSION-ATTEND	46.00	12.47	
27	CARBON PLANT	TRANSMISSION-ATTEND	138.00	13.80	
28	EMERY	TRANSMISSION-ATTEND	138.00	6.90	69.00
29	GADSBY PLANT	TRANSMISSION-ATTEND	138.00	13.80	46.00
30	GADSBY	TRANSMISSION-ATTEND	138.00	46.00	
31	HUNTER PLANT	TRANSMISSION-ATTEND	345.00	23.00	
32	HUNTINGTON PLANT	TRANSMISSION-ATTEND	345.00	23.00	
33	Total		1288.00	138.97	115.00
34	NUMBER OF SUBSTATIONS TRANS ATTENDED - 7				
35					
36	90TH SOUTH	TRANSMISSION-UNATTEN	345.00	138.00	
37	ABAJO	TRANSMISSION-UNATTEN	138.00	69.00	
38	ASHLEY	TRANSMISSION-UNATTEN	138.00	46.00	
39	BARNEY	TRANSMISSION-UNATTEN	138.00	46.00	
40	BEN LOMOND	TRANSMISSION-UNATTEN	345.00	230.00	138.00

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
30	1					1
175	3					2
289	7					3
8	1					4
114	2					5
97	2					6
164	2					7
22	1					8
340	4					9
135	3					10
97	2					11
51	7					12
180	3					13
26	4					14
100	2					15
3	4	3				16
600	5					17
358	4					18
1108	6	2				19
130	2					20
158	3					21
30	1					22
4350	72	5				23
						24
						25
25	1					26
225	5					27
783	13	1				28
568	17					29
318	2					30
1513	5	1				31
981	4					32
4413	47	2				33
						34
						35
1538	6	1				36
67	1					37
133	2					38
100	1					39
1813	5					40

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
SUBSTATIONS					
<p>1. Report below the information called for concerning substations of the respondent as of the end of the year.</p> <p>2. Substations which serve only one industrial or street railway customer should not be listed below.</p> <p>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.</p> <p>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).</p>					
Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	BLACKHAWK	TRANSMISSION-UNATTEN	138.00	69.00	46.00
2	BOOKCLIFFS	TRANSMISSION-UNATTEN	69.00	46.00	
3	CAMERON	TRANSMISSION-UNATTEN	138.00	46.00	
4	CAMP WILLIAMS	TRANSMISSION-UNATTEN	345.00	138.00	12.47
5	CARBON	TRANSMISSION-UNATTEN	46.00	2.40	
6	COLUMBIA	TRANSMISSION-UNATTEN	138.00	46.00	
7	CRICKET MOUNTAIN REG STA	TRANSMISSION-UNATTEN	46.00	46.00	
8	CUTLER	TRANSMISSION-UNATTEN	138.00	46.00	
9	EL MONTE	TRANSMISSION-UNATTEN	138.00	46.00	
10	GARKANE	TRANSMISSION-UNATTEN	69.00	46.00	
11	GREEN CANYON	TRANSMISSION-UNATTEN	138.00	46.00	
12	GRINDING	TRANSMISSION-UNATTEN	138.00	13.80	
13	HELPER	TRANSMISSION-UNATTEN	138.00	46.00	
14	HONEYVILLE	TRANSMISSION-UNATTEN	138.00	46.00	
15	HORSESHOE	TRANSMISSION-UNATTEN	138.00	46.00	12.47
16	HUNTINGTON	TRANSMISSION-UNATTEN	345.00	138.00	69.00
17	JERUSALEM	TRANSMISSION-UNATTEN	138.00	46.00	
18	LAMPO	TRANSMISSION-UNATTEN	138.00	46.00	
19	MCFADDEN	TRANSMISSION-UNATTEN	138.00	46.00	
20	MIDDLETON	TRANSMISSION-UNATTEN	138.00	69.00	34.50
21	MIDVALLEY	TRANSMISSION-UNATTEN	345.00	138.00	
22	MIDWAY CITY	TRANSMISSION-UNATTEN	138.00	46.00	
23	MINERAL PRODUCTS	TRANSMISSION-UNATTEN	69.00	46.00	
24	MOAB	TRANSMISSION-UNATTEN	138.00	69.00	
25	NEBO	TRANSMISSION-UNATTEN	138.00	46.00	
26	OLMSTED	TRANSMISSION-UNATTEN	46.00	2.40	
27	PAROWAN VALLEY	TRANSMISSION-UNATTEN	230.00	138.00	34.50
28	PAVANT	TRANSMISSION-UNATTEN	230.00	46.00	
29	PINTO	TRANSMISSION-UNATTEN	345.00	138.00	69.00
30	RED BUTTE	TRANSMISSION-UNATTEN	230.00	138.00	
31	SAND COVE HYDRO	TRANSMISSION-UNATTEN	34.50	2.40	
32	SIGURD	TRANSMISSION-UNATTEN	345.00	230.00	138.00
33	SMITHFIELD	TRANSMISSION-UNATTEN	138.00	46.00	12.47
34	SPANISH FORK	TRANSMISSION-UNATTEN	345.00	138.00	46.00
35	ST GEORGE	TRANSMISSION-UNATTEN	138.00	16.50	
36	UPPER BEAVER HYDRO	TRANSMISSION-UNATTEN	46.00	2.30	
37	WEBER PLANT	TRANSMISSION-UNATTEN	46.00	2.30	
38	WEST CEDAR	TRANSMISSION-UNATTEN	230.00	138.00	34.50
39	Total		7187.50	2986.10	646.91
40	NUMBER OF SUBSTATIONS TRANS UNATTENDED - 43				

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
100	2					1
6	3	1				2
25	3					3
169	2					4
8	1					5
33	1					6
15	1					7
70	2					8
313	3					9
33	1					10
67	2					11
225	3					12
142	2					13
35	1					14
80	2					15
270	4					16
67	1					17
75	1					18
45	1					19
141	4					20
900	2					21
67	1					22
13	1					23
67	1					24
68	2					25
15	1					26
138	2					27
133	2					28
258	3					29
400	1					30
	1					31
1124	6					32
63	2					33
1017	5					34
100	3	1				35
5	1					36
7	1					37
131	2					38
10076	92	3				39
						40

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1					
2	Washington				
3	ATTALIA	DISTRIBUTION-UNATTEN	69.00	12.47	
4	BOWMAN	DISTRIBUTION-UNATTEN	69.00	12.47	
5	CASCADE KRAFT	DISTRIBUTION-UNATTEN	69.00	12.47	4.16
6	CLINTON	DISTRIBUTION-UNATTEN	115.00	12.47	
7	DAYTON	DISTRIBUTION-UNATTEN	69.00	12.47	
8	DODD ROAD	DISTRIBUTION-UNATTEN	69.00	20.80	
9	GRANDVIEW	DISTRIBUTION-UNATTEN	115.00	12.47	69.00
10	HOPLAND	DISTRIBUTION-UNATTEN	115.00	12.47	
11	MILL CREEK	DISTRIBUTION-UNATTEN	69.00	12.47	
12	NACHES HYDRO	DISTRIBUTION-UNATTEN	115.00	12.47	
13	NOB HILL	DISTRIBUTION-UNATTEN	115.00	12.47	
14	NORTH PARK	DISTRIBUTION-UNATTEN	115.00	12.47	
15	ORCHARD	DISTRIBUTION-UNATTEN	115.00	12.47	
16	PACIFIC	DISTRIBUTION-UNATTEN	115.00	12.47	
17	POMEROY	DISTRIBUTION-UNATTEN	69.00	12.47	
18	PROSPECT POINT	DISTRIBUTION-UNATTEN	69.00	12.47	
19	PUNKIN CENTER	DISTRIBUTION-UNATTEN	115.00	12.47	
20	RIVER ROAD	DISTRIBUTION-UNATTEN	115.00	12.47	
21	SELAH	DISTRIBUTION-UNATTEN	115.00	12.47	
22	SULPHUR CREEK	DISTRIBUTION-UNATTEN	115.00	12.47	
23	SUNNYSIDE	DISTRIBUTION-UNATTEN	115.00	12.47	
24	TIETON	DISTRIBUTION-UNATTEN	115.00	12.47	34.50
25	TOPPENISH	DISTRIBUTION-UNATTEN	115.00	12.47	
26	TOUCHET	DISTRIBUTION-UNATTEN	69.00	12.47	
27	VOELKER	DISTRIBUTION-UNATTEN	115.00	12.47	
28	WAITSBURG	DISTRIBUTION-UNATTEN	69.00	12.47	
29	WAPATO	DISTRIBUTION-UNATTEN	115.00	12.47	
30	WENAS	DISTRIBUTION-UNATTEN	115.00	12.47	
31	WHITE SWAN	DISTRIBUTION-UNATTEN	115.00	12.47	
32	WILEY	DISTRIBUTION-UNATTEN	115.00	12.47	
33	Total		2990.00	382.43	107.66
34	NUMBER OF SUBSTATIONS DIST UNATTENDED - 30				
35					
36	CENTRAL	T/D-UNATTENDED	69.00	12.47	
37	UNION GAP	T/D-UNATTENDED	230.00	115.00	12.47
38	Total		299.00	127.47	12.47
39	NUMBER OF SUBSTATIONS T/D UNATTENDED - 2				
40					

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SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
						1
						2
25	1					3
45	2					4
117	6					5
25	1					6
23	2					7
25	4					8
56	2					9
34	2					10
45	2					11
20	1					12
42	2					13
45	2					14
50	2					15
28	3					16
9	1					17
40	2					18
20	2					19
51	4					20
45	2					21
25	1					22
45	2					23
29	2					24
50	2					25
6	1					26
25	1					27
9	1					28
45	2					29
25	2					30
22	2					31
45	2					32
1071	61					33
						34
						35
14	1					36
348	5					37
362	6					38
						39
						40

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	CONDIT PLANT	TRANSMISSION-ATTEND	69.00	2.30	
2	MERWIN PLANT	TRANSMISSION-ATTEND	115.00	13.20	
3	YALE PLANT	TRANSMISSION-ATTEND	230.00	13.80	
4	Total		414.00	29.30	
5	NUMBER OF SUBSTATIONS TRANS ATTENDED - 3				
6					
7	OUTLOOK	TRANSMISSION-UNATTEN	230.00	115.00	
8	PASCO	TRANSMISSION-UNATTEN	115.00	69.00	7.20
9	POMONA HEIGHTS	TRANSMISSION-UNATTEN	230.00	115.00	
10	SWIFT 1 PLANT	TRANSMISSION-UNATTEN	230.00	13.00	
11	WALLA WALLA 230KV	TRANSMISSION-UNATTEN	230.00	69.00	
12	WALLULA	TRANSMISSION-UNATTEN	230.00	69.00	
13	Total		1265.00	450.00	7.20
14	NUMBER OF SUBSTATIONS TRANS UNATTENDED - 6				
15					
16	Wyoming				
17	AIR BASE	DISTRIBUTION-UNATTEN	12.47	2.40	
18	ANTELOPE MINE	DISTRIBUTION-UNATTEN	230.00	34.50	
19	ASTLE STREET	DISTRIBUTION-UNATTEN	34.50	13.20	
20	BAILEY DOME	DISTRIBUTION-UNATTEN	57.00	12.47	
21	BAR X	DISTRIBUTION-UNATTEN	230.00	34.50	
22	BID MUDDY	DISTRIBUTION-UNATTEN	69.00	12.47	
23	BIG PINEY	DISTRIBUTION-UNATTEN	69.00	24.90	
24	BLACKS FORK	DISTRIBUTION-UNATTEN	230.00	34.50	
25	BRIDGER PUMP	DISTRIBUTION-UNATTEN	230.00	34.50	13.20
26	BRYAN	DISTRIBUTION-UNATTEN	115.00	12.47	
27	BUFFALO TOWN	DISTRIBUTION-UNATTEN	20.80	4.16	
28	BYRON	DISTRIBUTION-UNATTEN	34.50	4.16	
29	CASSA	DISTRIBUTION-UNATTEN	57.00	20.80	
30	CENTER STREET	DISTRIBUTION-UNATTEN	115.00	4.16	
31	CHAPMAN STATION	DISTRIBUTION-UNATTEN	46.00	12.47	
32	CHATHAM	DISTRIBUTION-UNATTEN	34.50	4.16	
33	CHUKAR	DISTRIBUTION-UNATTEN	12.47	4.16	
34	CHURCH AND DWIGHT	DISTRIBUTION-UNATTEN	34.50	0.48	
35	COKEVILLE	DISTRIBUTION-UNATTEN	46.00	24.90	
36	COLUMBIA-GENEVA	DISTRIBUTION-UNATTEN	230.00	13.80	
37	COMMUNITY PARK	DISTRIBUTION-UNATTEN	69.00	12.47	
38	CROOKS GAP	DISTRIBUTION-UNATTEN	34.50	12.47	
39	DEER CREEK	DISTRIBUTION-UNATTEN	69.00	12.47	
40	DJ COAL MINE	DISTRIBUTION-UNATTEN	69.00	34.50	

Name of Respondent PacifiCorp		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/03/2008		Year/Period of Report End of 2007/Q4	
SUBSTATIONS (Continued)							
<p>5. Show in columns (i), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.</p> <p>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.</p>							
Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.	
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)		
13	6	1				1	
183	9	1				2	
144	3	1				3	
340	18	3				4	
						5	
						6	
125	1					7	
39	9					8	
300	2					9	
261	3	1				10	
300	2					11	
120	2					12	
1145	19	1				13	
						14	
						15	
						16	
1	3					17	
25	1					18	
13	1					19	
2	1					20	
25	1					21	
7	1					22	
8	1					23	
150	2					24	
73	4					25	
25	1					26	
2	3					27	
2	3					28	
2	6	1				29	
13	1					30	
4	1					31	
	3					32	
1	3					33	
3	2					34	
4	1					35	
45	2					36	
40	2					37	
5	3					38	
9	1					39	
13	1					40	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	DOUGLAS	DISTRIBUTION-UNATTEN	57.00	2.30	
2	DRY FORK	DISTRIBUTION-UNATTEN	69.00	4.16	
3	ELK BASIN	DISTRIBUTION-UNATTEN	34.50	7.20	
4	EMIGRANT	DISTRIBUTION-UNATTEN	115.00	12.47	
5	EVANS	DISTRIBUTION-UNATTEN	69.00	12.47	
6	EVANSTON	DISTRIBUTION-UNATTEN	138.00	12.47	
7	FARMERS UNION	DISTRIBUTION-UNATTEN	34.50	4.16	
8	FIREHOLE	DISTRIBUTION-UNATTEN	230.00	34.50	
9	FORT CASPER	DISTRIBUTION-UNATTEN	69.00	12.47	
10	FORT SANDERS	DISTRIBUTION-UNATTEN	115.00	13.20	
11	FRANNIE	DISTRIBUTION-UNATTEN	230.00	34.50	
12	FRONTIER	DISTRIBUTION-UNATTEN	69.00	4.16	
13	GARLAND	DISTRIBUTION-UNATTEN	230.00	34.50	
14	GLENDO	DISTRIBUTION-UNATTEN	57.00	4.16	
15	GRASS CREEK	DISTRIBUTION-UNATTEN	230.00	34.50	
16	GREAT DIVIDE	DISTRIBUTION-UNATTEN	115.00	34.50	
17	GREYBULL	DISTRIBUTION-UNATTEN	34.50	4.16	
18	HANNA	DISTRIBUTION-UNATTEN	34.50	12.47	
19	JACKALOPE	DISTRIBUTION-UNATTEN	115.00	12.47	
20	KEMMERER	DISTRIBUTION-UNATTEN	69.00	24.90	
21	KIRBY CREEK PUMPING STATION	DISTRIBUTION-UNATTEN	34.50	2.40	
22	KIRBY CREEK	DISTRIBUTION-UNATTEN	34.50	4.16	
23	LANDER	DISTRIBUTION-UNATTEN	34.50	12.47	
24	LARAMIE	DISTRIBUTION-UNATTEN	115.00	13.20	
25	LATHAM	DISTRIBUTION-UNATTEN	230.00	34.50	
26	LINCH	DISTRIBUTION-UNATTEN	69.00	13.80	
27	LITTLE MOUNTAIN	DISTRIBUTION-UNATTEN	230.00	34.50	
28	LOVELL	DISTRIBUTION-UNATTEN	34.50	4.16	
29	MANDERSON	DISTRIBUTION-UNATTEN	34.50	4.16	
30	MILL IRON	DISTRIBUTION-UNATTEN	34.50	13.80	
31	MILLS	DISTRIBUTION-UNATTEN	12.47	4.16	
32	MURPHY DOME	DISTRIBUTION-UNATTEN	34.50	13.20	
33	NUGGETT	DISTRIBUTION-UNATTEN	69.00	7.20	
34	OPAL	DISTRIBUTION-UNATTEN	46.00	24.90	
35	ORIN	DISTRIBUTION-UNATTEN	57.00	12.47	
36	ORPHA	DISTRIBUTION-UNATTEN	57.00	7.20	
37	PARCO	DISTRIBUTION-UNATTEN	34.50	12.47	
38	PINEDALE	DISTRIBUTION-UNATTEN	69.00	24.90	
39	PITCHFORK	DISTRIBUTION-UNATTEN	69.00	24.90	
40	POINT OF ROCKS	DISTRIBUTION-UNATTEN	230.00	34.50	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
6	3					1
9	1					2
5	1					3
13	1					4
9	1					5
40	2					6
2	3					7
50	2					8
25	1					9
20	1					10
50	2					11
6	1					12
45	2					13
3	4					14
25	1					15
20	1					16
3	1					17
6	1					18
25	1					19
10	1					20
3	3					21
2	3					22
25	2					23
50	2					24
25	1					25
13	1					26
20	1					27
4	3					28
1	3					29
13	1	1				30
1	3					31
5	1					32
	1					33
8	1					34
2	3					35
3	3					36
5	1					37
8	1					38
17	9	2				39
25	1					40

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	POISON SPIDER	DISTRIBUTION-UNATTEN	69.00	2.40	
2	POLECAT	DISTRIBUTION-UNATTEN	34.50	12.47	
3	RAINBOW	DISTRIBUTION-UNATTEN	34.50	13.20	
4	RAVEN	DISTRIBUTION-UNATTEN	230.00	34.50	
5	RED BUTTE	DISTRIBUTION-UNATTEN	69.00	12.47	
6	REFINERY	DISTRIBUTION-UNATTEN	115.00	12.47	
7	SAGE HILL	DISTRIBUTION-UNATTEN	34.50	13.20	
8	SHOSHONI	DISTRIBUTION-UNATTEN	34.50	2.40	
9	SLATE CREEK	DISTRIBUTION-UNATTEN	69.00	12.47	
10	SOUTH CODY	DISTRIBUTION-UNATTEN	69.00	24.90	
11	SOUTH ELK BASIN	DISTRIBUTION-UNATTEN	34.50	4.16	
12	SOUTH TRONA	DISTRIBUTION-UNATTEN	230.00	34.50	
13	SPRING CREEK	DISTRIBUTION-UNATTEN	115.00	13.20	
14	SVILAR	DISTRIBUTION-UNATTEN	34.50	4.16	
15	TEN MILE	DISTRIBUTION-UNATTEN	69.00	34.50	
16	THERMOPOLIS TOWN	DISTRIBUTION-UNATTEN	34.50	4.16	
17	THUNDER CREEK	DISTRIBUTION-UNATTEN	57.00	12.47	
18	VETERANS	DISTRIBUTION-UNATTEN	34.50	13.20	
19	WELCH	DISTRIBUTION-UNATTEN	57.00	2.40	
20	WERTZ-SINCLAIR	DISTRIBUTION-UNATTEN	57.00	4.16	12.50
21	WEST ADAMS	DISTRIBUTION-UNATTEN	34.50	4.16	
22	WESTERN CLAY	DISTRIBUTION-UNATTEN	34.50	0.48	
23	WESTVACO	DISTRIBUTION-UNATTEN	230.00	34.50	
24	WORLAND TOWN	DISTRIBUTION-UNATTEN	34.50	4.16	
25	WYOPO	DISTRIBUTION-UNATTEN	230.00	34.50	
26	WYUTA	DISTRIBUTION-UNATTEN	46.00	12.47	
27	Total		7885.21	1357.50	25.70
28	NUMBER OF SUBSTATIONS DIST UNATTENDED- 90				
29					
30	LABARGE	T/D-UNATTENDED	69.00	24.90	
31	BUFFALO	T/D-UNATTENDED	230.00	20.80	
32	HILLTOP	T/D-UNATTENDED	115.00	34.50	20.80
33	RIVERTON 230	T/D-UNATTENDED	230.00	12.47	34.50
34	YELLOWCAKE	T/D-UNATTENDED	230.00	34.50	
35	Total		874.00	127.17	55.30
36	NUMBER OF SUBSTATIONS T/D UNATTENDED - 5				
37					
38	DAVE JOHNSTON PLANT	TRANSMISSION-ATTEND	230.00	115.00	69.00
39	JIM BRIDGER 345KV	TRANSMISSION-ATTEND	345.00	230.00	34.50
40	JIM BRIDGER UNITS 1-4	TRANSMISSION-ATTEND	345.00	22.00	

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
3	1					1
2	3					2
13	1					3
200	2					4
20	1					5
45	2					6
6	1					7
2	3					8
1	1					9
14	3	1				10
2	6					11
150	2					12
25	1					13
2	3					14
13	1					15
5	1					16
9	1					17
25	2					18
3	3					19
2	6					20
3	1					21
1	1					22
25	1					23
5	1					24
20	1	1				25
	1					26
1670	173	6				27
						28
						29
8	6					30
20	1					31
45	2	1				32
50	3					33
25	1					34
148	13	1				35
						36
						37
1358	17					38
1084	22					39
1122	2					40

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	NAUGHTON	TRANSMISSION-ATTEND	230.00	69.00	
2	WYODAK 230KV	TRANSMISSION-ATTEND	230.00	69.00	
3	WYODAK PLANT	TRANSMISSION-ATTEND	230.00	22.00	
4	Total		1610.00	527.00	103.50
5	NUMBER OF SUBSTATIONS TRANS ATTENDED - 6				
6					
7	BAIROIL	TRANSMISSION-UNATTEN	115.00	34.50	57.00
8	CASPER	TRANSMISSION-UNATTEN	230.00	115.00	69.00
9	CHAPPELL CREEK	TRANSMISSION-UNATTEN	230.00	69.00	
10	FOOTE CREEK WIND FARM	TRANSMISSION-UNATTEN	230.00	34.50	
11	GLENDO AUTO	TRANSMISSION-UNATTEN	69.00	57.00	
12	MANSFACE	TRANSMISSION-UNATTEN	230.00	34.50	
13	MIDWEST	TRANSMISSION-UNATTEN	230.00	69.00	34.50
14	MINERS	TRANSMISSION-UNATTEN	230.00	115.00	34.50
15	MUSTANG	TRANSMISSION-UNATTEN	230.00	115.00	
16	OREGON BASIN	TRANSMISSION-UNATTEN	230.00	34.50	69.00
17	PLATTE	TRANSMISSION-UNATTEN	230.00	115.00	34.50
18	RAILROAD	TRANSMISSION-UNATTEN	230.00	138.00	
19	ROCK SPRINGS 230	TRANSMISSION-UNATTEN	230.00	34.50	
20	SAGE	TRANSMISSION-UNATTEN	69.00	46.00	
21	THERMOPOLIS	TRANSMISSION-UNATTEN	230.00	115.00	
22	YELLOWTAIL	TRANSMISSION-UNATTEN	230.00	161.00	
23	Total		3243.00	1287.50	298.50
24	NUMBER OF SUBSTATIONS TRANS UNATTENDED - 16				
25					
26					
27	CALIFORNIA				
28	Distribution - 45				
29	T/D - 3				
30	Transmission - 9				
31					
32	IDAHO				
33	Distribution - 67				
34	T/D - 4				
35	Transmission - 18				
36					
37	OREGON				
38	Distribution - 181				
39	T/D - 10				
40	Transmission - 41				

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
1232	15	1				1
60	1					2
503	3	1				3
5359	60	2				4
						5
						6
53	3					7
517	6					8
67	1					9
196	2					10
15	2					11
20	1					12
91	4					13
58	4	1				14
200	2					15
115	4					16
165	4					17
400	1					18
75	3					19
22	1					20
175	2					21
100	1					22
2269	41	1				23
						24
						25
						26
						27
332						28
129						29
446						30
						31
						32
796						33
314						34
2642						35
						36
						37
4409						38
1238						39
6413						40

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS

- Report below the information called for concerning substations of the respondent as of the end of the year.
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- Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
- Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1					
2	UTAH				
3	Distribution - 298				
4	T/D - 23				
5	Transmission - 50				
6					
7	WASHINGTON				
8	Distribution - 30				
9	T/D - 2				
10	Transmission - 9				
11					
12	WYOMING				
13	Distribution - 90				
14	T/D - 5				
15	Transmission - 22				
16					
17	ALL STATES				
18	Distribution - 711				
19	T/D - 47				
20	Transmission - 149				
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent PacifiCorp	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report End of 2007/Q4
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SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
						1
						2
5164						3
4350						4
14489						5
						6
						7
1071						8
362						9
1485						10
						11
						12
1670						13
148						14
7628						15
						16
						17
13442						18
6541						19
33103						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/03/2008	Year/Period of Report 2007/Q4
PacifiCorp			
FOOTNOTE DATA			

Schedule Page: 426.9 Line No.: 32 Column: a

The Dixonville 500kV Substation is jointly owned by the respondent and the Bonneville Power Administration ("the BPA"). Ownership of the substation is as follows: PacifiCorp 50.0%, the BPA 50.0%. Operation and maintenance costs are shared between the two parties and responsibility is as follows: PacifiCorp 58.0%, and the BPA 42.0%.

Schedule Page: 426.10 Line No.: 4 Column: a

The Meridian 500kV Substation is jointly owned by the respondent and the Bonneville Power Administration ("the BPA"). Ownership of the substation is as follows: PacifiCorp 50.0%, the BPA 50.0%. Operation and maintenance costs are shared between the two parties and responsibility is as follows: PacifiCorp 58.0%, and the BPA 42.0%.

Schedule Page: 426.23 Line No.: 39 Column: a

The Jim Bridger 345kV Substation is jointly owned by the respondent and Idaho Power Company. Ownership of the substation is as follows: PacifiCorp 66.7%, Idaho Power Company 33.3%. Operation and maintenance costs are shared between the two parties and responsibility is as follows: PacifiCorp 66.7%, and Idaho Power Company 33.3%.

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