| THIS FILING IS | |
|---|---|
| Item 1: [X] An Initial (Original) Submission | OR [ ] Resubmission No. ____ |

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

PAC-E



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

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

| Exact Legal Name of Respondent (Company) | Year/Period of Report |
|---|---|
| PacifiCorp | End of 2008/Q4 |

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

## GENERAL INFORMATION

### I. Purpose

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

### II. Who Must Submit

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

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

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

### III. What and Where to Submit

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

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

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

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

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

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

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

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

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

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

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

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

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

**IV. When to Submit:**

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

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

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

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

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

## GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

## EXCERPTS FROM THE LAW

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

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

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

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

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

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

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

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

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

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

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

**General Penalties**

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

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

## IDENTIFICATION

| 01 Exact Legal Name of Respondent | 02 Year/Period of Report |
|---|---|
| PacifiCorp | End of 2008/Q4 |

03 Previous Name and Date of Change *(if name changed during year)*

/ /

04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)*

825 N.E. Multnomah, Suite 1900, Portland, OR 97232

| 05 Name of Contact Person | 06 Title of Contact Person |
|---|---|
| Henry E. Lay | 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* | 09 This Report Is | 10 Date of Report *(Mo, Da, Yr)* |
|---|---|---|
| (503) 813-6179 | (1) ☒ An Original (2) ☐ A Resubmission | 03/31/2009 |

## 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 | 03 Signature | 04 Date Signed *(Mo, Da, Yr)* |
|---|---|---|
| Douglas K. Stuver | Douglas K. Stuver | 03/31/2009 |
| 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 | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## LIST OF SCHEDULES (Electric Utility)

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

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

LIST OF SCHEDULES (Electric Utility) (continued)

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

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".

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## GENERAL INFORMATION

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

Douglas K. Stuver, Senior Vice President and Chief Financial Officer
825 N.E. Multnomah, Suite 1900
Portland, OR 97232-4116

Corporate Books are kept at:
825 N.E. Multnomah, Suite 1900
Portland, OR 97232-4116

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.

Incorporated on August 11, 1987 in the State of Oregon

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

Not applicable

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

PacifiCorp, which includes PacifiCorp and its subsidiaries, is a United States regulated electric 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 delivers electricity to customers in Utah, Wyoming and Idaho under the trade name Rocky Mountain Power and to customers in Oregon, Washington and California under the trade name Pacific Power. PacifiCorp's electric generation, commercial and energy trading, and coal-mining functions are operated under the name PacifiCorp Energy.

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

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

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## CONTROL OVER RESPONDENT

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

Berkshire Hathaway Inc.

MidAmerican Energy Holdings Company (100%) (88.25% controlled by Berkshire Hathaway Inc.)

PPW Holdings LLC (100% controlled by MidAmerican Energy Holdings Company)

PacifiCorp (100% of common stock held by PPW Holdings LLC)

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## CORPORATIONS CONTROLLED BY RESPONDENT

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

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

| Line No. | Name of Company Controlled (a) | Kind of Business (b) | Percent Voting Stock Owned (c) | Footnote Ref. (d) |
|---|---|---|---|---|
| 1 | 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 | |
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***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.: 8 Column: a***

Effective July 28, 2008, Canopy Botanicals SRL, a Bolivian Corpration and an indirect subsidiary of PacifiCorp Future Generations, was dissolved.

***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%).

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## OFFICERS

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

| Line No. | Title (a) | Name of Officer (b) | Salary for Year (c) |
|---|---|---|---|
| 1 | Executive Officers as of December 31, 2008 | | |
| 2 | Chairman of the Board and Chief Executive Officer | Gregory E. Abel | |
| 3 | Senior Vice President and Chief Financial Officer | Douglas K. Stuver | 215,499 |
| 4 | President, Rocky Mountain Power | A. Richard Walje | 345,000 |
| 5 | President, Pacific Power | R. Patrick Reiten | 258,000 |
| 6 | President, PacifiCorp Energy | A. Robert Lasich | 230,000 |
| 7 | | | |
| 8 | Other Executive Officers in 2008 | | |
| 9 | Senior Vice President and Chief Financial Officer | David J. Mendez | 144,696 |
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***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, 2008, 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, 2008 (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. Mr. Stuver was elected Senior Vice President and Chief Financial Officer, effective March 1, 2008.

***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, 2008, 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. On February 8, 2008, Mr. Mendez resigned as a director and executive officer of PacifiCorp, effective February 29, 2008.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## DIRECTORS

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

| Line No. | Name (and Title) of Director<br>(a) | Principal Business Address<br>(b) |
|---|---|---|
| 1 | PacifiCorp Board of Directors as of December 31, 2008: | |
| 2 | Gregory E. Abel (Chairman of the Board and CEO, PacifiCorp) | 666 Grand Avenue, Suite DM29, Des Moines, Iowa 50309 |
| 3 | R. 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 2300, Salt Lake City, Utah 84140 |
| 5 | Douglas L. Anderson | 302 South 36th Street, Omaha, Nebraska 68131 |
| 6 | Brent E. Gale (Senior Vice President) | 825 NE Multnomah, Suite 2000, Portland, Oregon 97232 |
| 7 | Patrick J. Goodman | 666 Grand Avenue, Suite DM29, Des Moines, Iowa 50309 |
| 8 | A. Robert Lasich (President, PacifiCorp Energy) | 1407 West North Temple, Suite 320, Salt Lake City, Utah 84116 |
| 9 | Mark C. Moench (SVP & General Counsel, PacifiCorp and | |
| 10 | Rocky Mountain Power) | 201 South Main, Suite 2400, Salt Lake City, Utah 84140 |
| 11 | Natalie L. Hocken (VP and General Counsel, Pacific Power) | 825 NE Multnomah, Suite 2000, Portland, Oregon 97232 |
| 12 | | |
| 13 | | |
| 14 | | |
| 15 | Other Directors in 2008 | |
| 16 | David J. Mendez (SVP and CFO, PacifiCorp) | 825 NE Multnomah, Suite 1900, Portland, Oregon 97232 |
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***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.: 16 Column: a***

Mr. Mendez resigned as a director and executive officer of PacifiCorp effective February 29, 2008. 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.

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**(Next Page is 108)**

| Name of Respondent | This Report Is: | Date of Report | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## 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.

**ITEM 1.**

**Changes in Franchise Rights**

| State | Effective Date | Expiration Date | Fee<br>(Fee attached to franchise agreement) |
|---|---|---|---|
| **California (a)** | | | |
| None | | | |
| **Idaho (b)** | | | |
| Spencer | 07/10/2008 | 07/10/2038 | 2.0% |
| **Oregon (c)** | | | |
| Merrill | 04/03/2008 | 04/03/2018 | 5.0% |
| Coburg | 08/19/2008 | 08/19/2013 | 5.0% |
| **Utah (b)** | | | |
| Plymouth | 01/23/2008 | 01/23/2033 | - |
| Providence | 01/31/2008 | 01/31/2033 | 5.0% |
| Naples | 04/17/2008 | 04/17/2018 | 6.0% |
| Sunset | 04/18/2008 | 04/18/2018 | 6.0% |
| Davis County | 07/06/2008 | 07/06/2023 | - |
| West Bountiful | 09/09/2008 | 09/09/2018 | 6.0% |
| **Washington (b)** | | | |
| Toppenish | 09/15/2008 | 09/15/2028 | 8.5% |
| Columbia County | 10/06/2008 | 10/06/2043 | - |
| Pasco | 10/24/2008 | 10/24/2018 | - |
| **Wyoming (d)** | | | |
| Opal | 04/23/2008 | 04/23/2033 | 1.0% |

(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 fees 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.

(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.

## ITEM 2.

### Acquisition of Ownership in Other Companies

On September 15, 2008, after having received the requisite regulatory approvals, PacifiCorp acquired from TNA Merchant Projects, Inc., an affiliate of Suez Energy North America, Inc., 100% of the equity interests of Chehalis Power Generating, LLC ("Chehalis"), an entity owning a 520-megawatt ("MW") natural gas-fired generating plant located in Chehalis, Washington. The total cash purchase price was $308 million and the estimated fair value of the acquired entity was primarily allocated to the plant, which is included in account 102, Electric plant purchased or sold. Chehalis was merged into PacifiCorp immediately following the acquisition. The results of the plant's operations have been included in PacifiCorp's Financial Statements since the acquisition date. Commission authorizations associated with the acquisition were as follows:

- Federal Trade Commission - Transaction identification number 20081103, granted May 9, 2008.
- Federal Energy Regulatory Commission (the "FERC") - Docket No. EC08-82-000 issued July 17, 2008.
- Washington Energy Facility Site Evaluation Council - Order No. 836, effective July 8, 2008.
- Federal Communications Commission - File number 0003447617, consent dated May 23, 2008.
- Oregon Public Utility Commission (the "OPUC") - Order No. 08-376, effective July 17, 2008, granting the petition for waiver of the OPUC's competitive bidding guidelines.
- Utah Public Service Commission (the "UPSC") - Docket No. 08-035-35, dated August 30, 2008, granting the request for approval to acquire a significant energy resource.

## ITEM 3.

### Purchase or Sale of an Operating Unit

On September 14, 2007, PacifiCorp closed the sale of the Upper Beaver Hydroelectric Project, 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 April 2008, the FERC approved the journal entries called for by the Uniform System of Accounts. The sale was approved by the Wyoming Public Service Commission (the "WPSC"), the OPUC and the California Public Utilities Commission (the "CPUC").

For information regarding company acquisitions, refer to Important Changes During The Quarter/Year, Item 2 included in this Form No. 1.

## ITEM 4.

## Important Leaseholds

*Seven Mile Hill Wind Project*

In March 2008, PacifiCorp completed the purchase of the rights to the Seven Mile Hill wind site in Carbon County, Wyoming from Eurus Wind Power Development LLC. As part of this agreement, PacifiCorp was assigned two real estate leases, one with private landowners and one with the State of Wyoming. The lease with the private landowners has an initial term of 10 years with an automatic extension of 99 years if a certain milestone is met. The milestone has been met. The lease with the State of Wyoming has a 25-year term, with three 25-year extensions available at PacifiCorp's option, subject to certain lease renewal procedures. The leases have initial term rent payments, one-time installation fees based on installed megawatts of capacity and annual operating rent payments based on installed megawatts of capacity. Both leases also include minimum lease payment obligations.

*Chehalis Gas Lateral*

In September 2008, as part of the acquisition of Chehalis, PacifiCorp assumed a 25.5 year natural gas transportation agreement entered into during August 2001 with Northwest Pipeline Corporation ("Northwest"). The agreement sets forth the terms for Northwest's provision of natural gas transportation services to the Chehalis generating facility and Northwest's construction of a natural gas pipeline and facilities necessary to connect the Chehalis generating facility to Northwest's existing mainline. The estimated monthly charge includes reimbursement for the construction costs of the pipeline and facilities and other executory costs such as monthly operation and maintenance costs and property taxes. The monthly charge will be adjusted annually to reflect the actual costs incurred by Northwest. The agreement is considered a capital lease of the facilities resulting in a $4.7 million capital lease obligation and a $4.7 million capital lease asset. The agreement requires future minimum lease payments, including executory costs, of approximately $1.2 million per year for the years ending December 31, 2009 through December 31, 2027 and $0.4 million for the year ending December 31, 2028.

*High Plains Wind Project*

In September 2008, PacifiCorp completed the purchase of the rights to the High Plains wind site from GreenWing Pacific Energy Corporation. The wind site is located about five miles south of the town of Rock River, in Carbon and Albany counties, Wyoming. As part of this agreement, PacifiCorp was assigned two private landowner real estate leases. The leases with the private landowners have an initial term of 30 years from the original lease execution date of June 5, 2007 with an available extension of 30 years activated by written notice from PacifiCorp. The leases have minimum rent payments, one-time construction payments based on megawatts of rated capacity, and royalty payments based on generation.

## ITEM 5.

## Important Extension and Reduction of Transmission or Distribution System

For discussion of transmission lines added during the year, refer to pages 424-425 of this Form No. 1. During the year ended December 31, 2008, PacifiCorp did not significantly increase or decrease the capacity of its distribution system.

**ITEM 6.**

**Financing Activities**

*Short-Term Debt and Revolving Credit Agreements*

Regulatory authorities limit PacifiCorp to $1.5 billion of short-term debt, of which an aggregate principal amount of $85 million was outstanding as of December 31, 2008, with a weighted-average interest rate of 1.0%. In January 2009, PacifiCorp repaid its outstanding short-term debt with proceeds from its January 2009 long-term debt issuance discussed below. Commission authorizations for up to $1.5 billion outstanding at any one time in commercial paper and other unsecured short-term debt are as follows:

- OPUC - Docket No. UF-4120, 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, Order No. 29999, dated March 14, 2006.
- FERC - Docket No. ES07-61-000, dated November 26, 2007, letter order effective January 1, 2008.

As of December 31, 2008, PacifiCorp had $1.5 billion of total bank commitments under two unsecured revolving credit facilities. However, PacifiCorp's effective liquidity under these facilities was reduced by $105 million to $1.4 billion due to the Lehman Brothers Holdings Inc. ("Lehman") bankruptcy filing in September 2008. Lehman filed for protection under Chapter 11 of the Federal Bankruptcy Code in the United States Bankruptcy Court in the Southern District of New York. Lehman Brothers Bank, FSB and Lehman Commercial Paper, Inc., both subsidiaries of Lehman, have commitments totaling $105 million in PacifiCorp's $1.5 billion unsecured revolving credit facilities. The reduction in available capacity under the credit facilities as a result of the Lehman bankruptcy did not have a material adverse impact on PacifiCorp.

Adjusting for the Lehman bankruptcy, the first credit facility has $760 million of total bank commitments through July 6, 2011. The commitments reduce over time to $630 million of remaining availability for the year ending July 6, 2013. Adjusting for the Lehman bankruptcy, the second credit facility has $635 million of total bank commitments through October 23, 2012. Each credit facility includes a variable interest rate borrowing option based on the London Interbank Offered Rate, plus a margin that was 0.155% at February 27, 2009 and varies based on PacifiCorp's credit ratings for its senior unsecured long-term debt securities. These credit facilities support PacifiCorp's commercial paper program, unenhanced variable-rate tax-exempt bond obligations and other short-term borrowing needs.

As of December 31, 2008, PacifiCorp had no borrowings outstanding under either credit facility but had letters of credit under both credit agreements totaling $220 million to support variable-rate tax-exempt bond obligations. In addition, the credit facilities supported $85 million of commercial paper borrowings and $38 million of unenhanced variable-rate tax-exempt bond obligations outstanding as of December 31, 2008. The remaining $1.1 billion of effective liquidity under the unsecured revolving credit facilities was available as of December 31, 2008.

*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 Securities Exchange Commission covering future first mortgage bond issuances. PacifiCorp's long-term debt issuances in January 2009 and during the year ended December 31, 2008 were covered under the above-noted regulatory authorities and shelf registration statement.

In January 2009, PacifiCorp issued $350 million of its 5.50% First Mortgage Bonds due January 15, 2019 and $650 million of its 6.00% First Mortgage Bonds due January 15, 2039.

In July 2008, PacifiCorp issued $500 million of its 5.65% First Mortgage Bonds due July 15, 2018 and $300 million of its 6.35% First Mortgage Bonds due July 15, 2038.

State commission authorizations for the issuances above were as follows:

- OPUC - Docket No. UF-4243, Order No. 08-013, dated January 14, 2008.
- IPUC - Case No. PAC-E-07-16, Order No. 30489, dated January 22, 2008.

In September 2008, PacifiCorp acquired $216 million of its insured variable-rate tax-exempt bond obligations due to the significant reduction in market liquidity for insured variable-rate obligations. In November 2008, the associated insurance and related standby bond purchase agreements were terminated and these variable-rate long-term debt obligations were remarketed with credit enhancement and liquidity support provided by $220 million of letters of credit issued under PacifiCorp's two unsecured revolving credit facilities.

As of December 31, 2008, PacifiCorp had $517 million of letters of credit available to provide credit enhancement and liquidity support for variable-rate tax-exempt bond obligations totaling $504 million plus interest. These committed bank arrangements were fully available at December 31, 2008 and expire periodically through May 2012.

PacifiCorp may from time to time seek to acquire its outstanding securities through cash purchases in the open market, privately negotiated transactions or otherwise. Any debt securities repurchased by PacifiCorp may be reissued or resold by PacifiCorp from time to time and will depend on prevailing market conditions, PacifiCorp's liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

## ITEM 7.

### Changes in Articles of Incorporation or Amendments to Charter

On September 15, 2008, PacifiCorp acquired 100% of the ownership interests in Chehalis, and immediately thereafter merged Chehalis with and into PacifiCorp, with PacifiCorp surviving, such that the separate existence of Chehalis ceased. The merger was accomplished by the recordation of Articles of Merger with the Secretary of State for the state of Oregon, and a Certificate of Merger with the Secretary of State for the state of Delaware. These documents now appear in the articles of incorporation records of PacifiCorp.

## 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 Generation (UT, ID & WY) | 2.78% | 1/26/2008 | $ 1,026,679 |
| IBEW 57 Power Delivery (UT, ID & WY) | 2.78% | 1/26/2008 | 2,197,939 |
| Total | | | $ 3,224,618 |

(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 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), individual Karuk and Yurok Tribe members and 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 and cause 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 March 2008, the court dismissed the complaint following plaintiffs' failure to agree on the court's conditions for combining this case with the May 2007 case described below.

In May 2007, PacifiCorp was served with a complaint filed in the United States District Court for the Northern District of California by individual Karuk and Yurok Tribe members, a commercial fisherman, a resort owner and the Klamath Riverkeeper. The complaint similarly alleges that *microcystis aeruginosa* causes the plaintiffs physical, property and economic harm. In March 2008, one of the Yurok Tribe members voluntarily dismissed his claims in the case. In April 2008, the court entered a stipulation and order dismissing plaintiff Klamath Riverkeeper's claims, with prejudice. In July 2008, commercial fisherman Michael Hudson's claims were dismissed with prejudice, and PacifiCorp filed motions for summary judgment on all remaining plaintiffs for all remaining claims. In August 2008, plaintiff Leaf Hillman, Karuk Tribe member, voluntarily dismissed all his personal injury claims with prejudice. In September 2008, PacifiCorp filed a motion for summary judgment on all of plaintiffs' claims for public nuisance, private nuisance and negligence. In October 2008, the parties negotiated a final settlement in the matter and a stipulation was filed with the court dismissing all plaintiffs and all remaining claims, with prejudice.

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 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. In March 2008, the court indefinitely postponed the date for the liability-phase trial. The remedy-phase trial has not yet been scheduled. The court also has before it a number of motions on which it has not yet ruled. 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 was 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. In February 2008, the plaintiffs filed a petition requesting consideration of their appeal by the Utah Supreme Court. The plaintiff's request was granted and they filed a brief in November 2008 with the Utah Supreme Court. In January 2009, PacifiCorp filed its reply brief. 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.

In May 2004, PacifiCorp was served with a complaint filed in the United States District Court for the District of Oregon (the "District Court") 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 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 United States Court of Appeals for the Ninth Circuit (the "Ninth Circuit") and briefing was completed in March 2006. In February 2008, the Ninth Circuit affirmed the District Court's 2005 decisions dismissing the case. In May 2008, the plaintiffs filed a petition requesting review by the United States Supreme Court. PacifiCorp filed a brief in opposition to the petition in June 2008. In October 2008, the United States Supreme Court denied plaintiffs' petition for review.

For further information regarding material developments to legal proceedings pending at December 31, 2007, refer to Note 13 of Notes to Financial Statements included in this Form No. 1.

**ITEM 10.**

**Related Party Transactions**

None.

**ITEM 11.**

(Reserved)

**ITEM 12.**

**General Regulation**

PacifiCorp is subject to comprehensive governmental regulation that significantly influences its operating environment, prices charged to customers, capital structure, costs and its ability to recover costs.

*Federal Regulation*

In addition to the discussion contained herein, refer to Note 13 of Notes to Financial Statements included in this Form No. 1 for further information regarding federal regulatory matters.

*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.

The FERC conducts a triennial review of PacifiCorp's market-based rate pricing authority in accordance with the filing schedule established by the FERC in Order No. 697. 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. PacifiCorp's next triennial filing is due in June 2010. Under the FERC's market-based rules, PacifiCorp must also file a notice of change in status upon the ownership or control of an additional 100 MW of incremental generation. Following the filing by PacifiCorp of a change in status notice relating to new generation, the FERC in November 2007 confirmed that PacifiCorp does not have market power and may continue to charge market-based rates. In October 2008, PacifiCorp filed a change in status notice, which is pending, related to its acquisition of the 520-MW Chehalis natural gas-fired generating facility and the expected commercial operation of several new PacifiCorp wind-powered generating facilities. Although PacifiCorp submitted studies to support a FERC conclusion consistent with its precedent that PacifiCorp continues to lack generation market power in all relevant markets, it is possible that the FERC could require PacifiCorp to adopt mitigation measures for a specific market.

*Transmission Investment*

In July 2008, PacifiCorp filed a petition for declaratory order with the FERC to confirm incentive rate treatment for the Energy Gateway Transmission Expansion Project. The Energy Gateway Transmission Expansion Project is an investment plan to build approximately 2,000 miles of new high-voltage transmission lines primarily in Wyoming, Utah, Idaho, Oregon and the desert Southwest. The plan, with an estimated cost exceeding $6.1 billion, includes projects that will address customer load growth, improve system reliability and deliver energy from new wind-powered and other renewable generating resources throughout PacifiCorp's six-state service area and the Western United States. Certain transmission segments associated with this plan are expected to be placed in service beginning 2010, with other segments placed in service through 2018, depending on siting, permitting and construction schedules. In October 2008, the FERC granted a 200-basis-point (two-percentage-point) incentive rate adder to PacifiCorp's base return on equity for seven of the eight project segments subject to a future Section 205 rate case filing with the FERC. The FERC did not preclude PacifiCorp from filing for incentive rate treatment for the remaining segment at a future date.

*FERC Orders No. 890 and 890-A and 890-B*

In February 2007, the FERC adopted a final rule in Order No. 890 designed to strengthen the pro forma Open Access Transmission Tariff ("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 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 OATT on file with the FERC, PacifiCorp is required to comply with the requirements of the new rule. PacifiCorp made its first compliance filing amending its OATT in July 2007. Subsequent to this filing, PacifiCorp was required to make additional compliance filings to revise its initial filing, all of which were accepted by the FERC through various orders issued in 2007 and 2008.

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 and requiring an additional compliance filing by transmission providers. In March 2008, PacifiCorp submitted its Order No. 890-A compliance filing, which was accepted by the FERC in November 2008. In June 2008, the FERC issued Order No. 890-B, which generally affirmed the provisions of the final rule as adopted in Order No. 890 and Order No. 890-A with certain additional limited clarifications, and which required an additional compliance filing. PacifiCorp filed its Order No. 890-B compliance filing in September 2008, which consisted of non-substantive grammatical revisions to its OATT and which was accepted by the FERC in December 2008. In addition to these filings, PacifiCorp filed other Order No. 890 related compliance filings, including a December 2007 filing proposing changes to its local, regional and sub-regional transmission planning process contained in its OATT. This filing, which is still pending before the FERC, is not anticipated to have a significant impact on PacifiCorp's financial results, but it could have a significant impact on its transmission planning functions.

*FERC Reliability Standards*

The FERC has approved 88 reliability standards developed by North American Electric Reliability Corporation (the "NERC") and 8 regional variations developed by the Western Electricity Coordinating Council (the "WECC"). Responsibility for compliance and enforcement of these standards has been given to the WECC. The 88 standards comprise over 600 requirements and sub-requirements with which PacifiCorp must comply. PacifiCorp expects that these standards will change as a result of modifications, guidance and clarification following industry implementation and ongoing audits and enforcement. In January 2008, the FERC approved eight additional cyber security and critical infrastructure protection standards proposed by the NERC. The additional standards became mandatory and enforceable in April 2008. PacifiCorp cannot predict the effect that these standards will have on its financial results; however, they will likely require increased expenditures for cyber security and other systems for PacifiCorp's critical assets and may have a significant impact on transmission operations and resource planning functions. During 2007, the WECC audited PacifiCorp's compliance with several of the approved reliability standards. In April 2008, PacifiCorp received a notice of a preliminary non-public investigation from the FERC and the NERC to determine whether an outage that occurred in PacifiCorp's transmission system in February 2008 involved any violations of reliability standards. In November 2008, PacifiCorp received preliminary findings from the FERC staff regarding its non-public investigation into the February 2008 outage. In November 2008, in conjunction with the reliability standard review, the FERC took over processing certain aspects of the WECC's 2007 audit. PacifiCorp is analyzing the preliminary results of the audit and the preliminary results of the non-public investigation, and at this time, cannot predict the impact of the audit or the non-public investigation, if any, on its financial results.

*Hydroelectric Relicensing*

PacifiCorp's Klamath hydroelectric system is the remaining hydroelectric generating facility actively engaged in the relicensing process with the FERC. PacifiCorp also has requested the FERC to allow decommissioning of certain hydroelectric systems. Most of PacifiCorp's hydroelectric generating facilities are licensed by the FERC as major systems under the Federal Power Act, and certain of these systems are licensed under the Oregon Hydroelectric Act. Refer to Note 13 of Notes to Financial Statements for an update regarding hydroelectric relicensing for PacifiCorp's Klamath, Lewis River and Prospect hydroelectric systems.

*Hydroelectric Decommissioning*

*Powerdale Hydroelectric Facility – Hood River, Oregon*

In June 2003, PacifiCorp entered into a settlement agreement to remove the 6-MW 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 system features, which is subject to the FERC and other regulatory approvals, is projected to cost $6 million, excluding inflation. Plant shut down and 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 plant; however, removal is still scheduled for 2010. Also in February 2007, PacifiCorp submitted a request to the FERC to allow PacifiCorp to defer the remaining net book value and any additional removal costs of this system 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 regulatory commissions to defer and recover these costs.

*Condit Hydroelectric Facility – White Salmon River, Washington*

In September 1999, a settlement agreement to remove the 14-MW Condit hydroelectric facility 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 would not begin until October 2008, with 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. Given the ongoing permitting process and the time needed for system removal and to evaluate impacts on natural resources, decommissioning is now expected to begin in October 2010. In March 2008, the United States Army Corps of Engineers requested PacifiCorp complete an additional study of expected decommissioning impacts on aquatic resources. The study work is complete and results have been provided to the United States Army Corps of Engineers and the Washington Department of Ecology. Absent further information requests, the Washington Department of Ecology is expected to complete the Clean Water Act 401 certification process during 2009. Remaining permitting includes a 404 permit from the United States Army Corps of Engineers and a surrender order from the FERC.

*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.

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 that resulted in the BPA suspending payments to the Pacific Northwest's six investor-owned utilities, including PacifiCorp. This resulted in increases to PacifiCorp's residential and small-farm customers' electric bills in Oregon, Washington and Idaho.

In February 2008, the BPA initiated a rate proceeding under the Northwest Power Act to reconsider the level of benefits for the years 2002 through 2006 consistent with the Ninth Circuit's decisions, as well as to re-establish the level of benefits for years 2007 and 2008 and to set the level of benefits for years 2009 and beyond. The BPA issued its final records of decision in September 2008 establishing rates for the time period of October 2008 through September 2009 and adopting a residential purchase and sale agreement for October 2008 through September 2011. In September 2008, the OPUC approved PacifiCorp's request to execute the residential purchase and sale agreement for the payment of Residential Exchange Program benefits from the BPA. In October 2008, the OPUC and WUTC approved PacifiCorp's filing of revised tariff sheets to resume residential exchange credits, effective November 1, 2008. Because these credits are passed through to PacifiCorp's customers, they do not significantly affect PacifiCorp's financial results.

In October 2008, the BPA offered PacifiCorp a long-term residential purchase and sale agreement for October 2011 through September 2028. In December 2008, the OPUC denied PacifiCorp's request to execute the residential purchase and sale agreement for these years. Also in December 2008, PacifiCorp filed two petitions with the Ninth Circuit for review of the BPA's final records of decision. Because these credits are passed through to PacifiCorp's customers, they do not significantly affect PacifiCorp's financial results.

*United States Mine Safety*

PacifiCorp's 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. PacifiCorp is required to develop a written emergency response plan specific to each underground mine it operates. 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 Regulation*

PacifiCorp is subject to comprehensive regulation by the UPSC, the OPUC, the WPSC, the WUTC, the IPUC and the CPUC. PacifiCorp pursues a regulatory program in all states, with the objective of keeping rates closely aligned to ongoing costs. The following table illustrates PacifiCorp's recovery mechanisms in each state jurisdiction in which PacifiCorp operates.

| State Regulator | Base Rate Test Period | Adjustment Mechanism (1) |
|---|---|---|
| Utah Public Service Commission | Forecasted or historical with known and measurable changes (2) | PacifiCorp has requested approval of an energy cost adjustment mechanism ("ECAM") to recover the difference between base power costs set during a general rate case and actual power costs. The application is currently pending before the UPSC. |
| Oregon Public Utility Commission | Forecasted | Annual transition adjustment mechanism ("TAM"), a mechanism for annual rate adjustments for forecasted net variable power costs; no true-up to actual net variable power costs.<br><br>Renewable adjustment clause ("RAC") to recover the revenue requirement of new renewable resources and associated transmission that are not reflected in general rates.<br><br>Annual SB 408 true-up of taxes authorized to be collected in rates compared to taxes paid by PacifiCorp, as defined by Oregon statute and administrative rules. |
| Wyoming Public Service Commission | Forecasted or historical with known and measurable changes (2) | Power cost adjustment mechanism ("PCAM") based on forecasted net power costs, later trued-up to actual net power costs. Subject to dead bands and customer sharing. |
| Washington Utilities and Transportation Commission | Historical with known and measurable changes | Deferral mechanism of costs for up to 24 months of new base load generation resources that qualify under the state's emissions performance standard and are not reflected in general rates. |
| Idaho Public Utilities Commission | Historical with known and measurable changes | PacifiCorp has requested approval of ECAM to recover the difference between base power costs set during a general rate case and actual power costs. The application is currently pending before the IPUC. |
| California Public Utilities Commission | Forecasted | Post test-year adjustment mechanism for major capital additions ("PTAM – capital additions"), a mechanism that allows for rate adjustments outside of the context of a traditional rate case for the revenue requirement associated with capital additions exceeding $50 million on a total-company basis. Filed as eligible capital additions are placed into service.<br><br>Post test-year adjustment mechanism for attrition ("PTAM – attrition"), a mechanism that allows for an annual adjustment to costs other than net variable power costs tied to the Consumer Price Index minus a 0.5% productivity offset.<br><br>Energy cost adjustment clause ("ECAC") that allows for an annual update to actual and forecasted net variable power costs. |

(1) Margins earned on wholesale sales for energy and capacity have historically been included as a component of retail cost of service upon which retail rates are based.

(2) PacifiCorp has relied on both historical test periods with known and measurable adjustments and forecasted test periods. The WPSC has not issued a final ruling on its preference between a historical or forecasted test period.

*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% based on a test period ended June 2009. The increase was primarily due to increased capital spending and net power costs, both of which are driven by load growth. In March 2008, PacifiCorp filed supplemental testimony reducing the requested rate increase to $100 million. The decrease was primarily a result of a UPSC-ordered change in the test period to the year ended December 2008 and reductions associated with recent UPSC orders on depreciation rate changes and two deferred accounting requests. Subsequently, hearings were held on the revenue requirement portion of the case and PacifiCorp filed additional testimony. In August 2008, the UPSC issued its revenue requirement order in the case, increasing rates by $36 million, or 3%. The new rates became effective August 13, 2008. In September 2008, PacifiCorp filed a petition for reconsideration of several elements of the order. In October 2008, the UPSC issued an order on the reconsideration petition allowing PacifiCorp to recover an additional $3 million, bringing the total rate increase to $39 million. A settlement that provides for an equal percentage increase to all tariff customers was reached in the rate-design phase of the case and was approved by the UPSC.

In July 2008, PacifiCorp filed a general rate case with the UPSC requesting an annual increase of $161 million, or an average price increase of 11%, prior to any consideration for the UPSC's order in the December 2007 case described above. In September 2008, PacifiCorp filed supplemental testimony that reflected then-current revenues and other adjustments based on the August 2008 order in the 2007 general rate case. The supplemental filing reduced PacifiCorp's request to $115 million. In October 2008, the UPSC issued an order changing the test period from the twelve months ending June 2009 using end-of-period rate base to the forecast calendar year 2009 using average rate base. In December 2008, PacifiCorp updated its filing to reflect the change in the test period. The updated filing proposes an increase of $116 million, or an average price increase of 8%. The UPSC issued an order resetting the beginning of the 240-day statutory time period required to process the case to the date of the September 2008 supplemental filing. Based on the new time period, the new rates, if approved, will become effective in May 2009. In February 2009, a settlement agreement was reached among the parties who had filed testimony in the cost of capital phase of the rate case. A stipulation was filed with the UPSC requesting that the UPSC set the weighted cost of capital at 8.4% with a return on equity at 10.6%. The UPSC approved the cost of capital settlement agreement by bench order in March 2009. Rebuttal testimony was filed with the UPSC for the 2008 general rate case in March 2009 which will support a rate increase of $57 million, or 4%, which reflects the cost of capital settlement. In March 2009, a settlement agreement was filed with the UPSC resolving all remaining revenue requirement issues resulting in parties agreeing, among other settlement terms, on a $45 million, or 3%, rate increase that would be effective on May 8, 2009. The UPSC will hold hearings on March 31, 2009 to address the approval of the revenue requirement settlement agreement.

In March 2009, PacifiCorp filed for an energy cost adjustment mechanism with the UPSC. The filing recommends the UPSC adopt the energy cost adjustment mechanism to recover the difference between base power costs set in the next Utah general rate case and actual power costs.

*Oregon*

In April 2008, PacifiCorp made its first annual renewable adjustment clause RAC filing to recover the revenue requirement related to eligible new renewable resources and associated transmission under the OREA that are not reflected in general rates. PacifiCorp requested an annual increase of $39 million on an Oregon-allocated basis, or an average price increase of 4%. In November 2008, the OPUC issued an order approving the RAC request with certain modifications. The OPUC excluded Oregon's share of the costs for the 99-MW Rolling Hills wind-powered generating plant from the request on the basis that PacifiCorp failed to prove the resource was prudently acquired. The OPUC's finding was primarily based on the conclusion that the capacity factor was less favorable compared to other unspecified Wyoming wind-powered generating projects PacifiCorp may have been able to acquire. In December 2008 and January 2009, PacifiCorp submitted compliance filings consistent with the OPUC order that together reduced the requested increase by $8 million to $31 million, or an average price increase of 3%. The OPUC approved $25 million, or 2%, to go into effect on January 1, 2009. The OPUC approved an additional $6 million, or 1%, to go into effect on January 21, 2009 for the 99-MW Seven Mile Hill wind-powered generating plant.

In July 2008, as part of its annual TAM, PacifiCorp filed updated forecasted net power costs for 2009. PacifiCorp proposed a net power cost increase of $57 million on an Oregon-allocated basis, or an average price increase of 6%. In September 2008, PacifiCorp filed a stipulation agreement reducing the proposed net power cost increase to $34 million on an Oregon-allocated basis, or an average price increase of 2%. The stipulation agreement was approved by the OPUC in November 2008. The forecasted net power costs were updated again in November 2008 for OPUC-ordered changes, changes to the forward price curve and new wholesale sales and purchases. In December 2008, PacifiCorp submitted a compliance filing in the TAM proceeding that reflected final forecasted net power costs and direct access transition adjustments for 2009. The compliance filing reduced PacifiCorp's request by an additional $15 million on an Oregon-allocated basis, which resulted in an increase of $9 million, or an average price increase of 1%, after adjusting for load growth. The compliance filing was approved in December 2008 and the new rates became effective January 1, 2009.

For a discussion of SB 408, refer to Note 5 of Notes to Financial Statements included in this Form No. 1.

*Wyoming*

In June 2007, PacifiCorp filed a general rate case with 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. The settlement provided for an annual rate increase of $23 million, or an average price increase of 5%. In addition, the parties also agreed to modify the current PCAM to use forecasted power costs in the future and to terminate the 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 approved by the WPSC in March 2008. The new rates were effective May 1, 2008.

In February 2008, PacifiCorp filed its annual PCAM application with the WPSC for costs incurred during the period December 1, 2006 through November 30, 2007. In March 2008, the WPSC approved PacifiCorp's request on an interim basis effective April 1, 2008, resulting in a rate increase of $31 million, or an average price increase of 8%, to recover deferred power costs over a one-year period. In August 2008, PacifiCorp reached an agreement with parties to the case to adjust the rate increase to $29 million. In November 2008, the WPSC issued an order approving the stipulation agreement. The interim rates were revised to reflect the $29 million increase approved in the stipulation agreement and became effective October 15, 2008.

In July 2008, PacifiCorp filed a general rate case with the WPSC requesting an annual increase of $34 million, or an average price increase of 7%, with an effective date in May 2009. Power costs have been excluded from the filing and will be addressed separately in PacifiCorp's annual PCAM application in February 2009. In October 2008, the general rate case request was reduced by $5 million, to $29 million, to reflect a change in the in-service date of the High Plains wind-powered generating plant. In March 2009, a settlement agreement was filed with the WPSC requesting an increase in Wyoming rates of $18 million annually beginning May 24, 2009, for an average overall increase of 4%. The WPSC held and completed public hearings on the 2008 rate case in March 2009. The WPSC issued a bench decision approving the stipulation agreement and an $18 million rate increase effective with service on and after May 24, 2009.

In February 2009, PacifiCorp filed its annual PCAM application with the WPSC. Pursuant to tariff changes made in the 2007 general rate case, the 2009 PCAM application includes a request to recover $27 million of deferred net power costs during the period December 1, 2007 through November 30, 2008 and to establish a new forecast base net power cost using the test period December 1, 2008 through November 30, 2009. The net effect of the deferred and forecast base net power cost is an increase in Wyoming rates of $19 million, or 4%. The tariff governing the power cost adjustment mechanism requires an effective date of April 1, 2009. As a result of the 2008 general rate case settlement agreement, PacifiCorp and certain parties agreed to request the WPSC implement an interim PCAM increase of $7 million until the docket is resolved and a final PCAM surcharge increase is determined. In March 2009, the WPSC approved PacifiCorp's motion to implement the interim rate increase of $7 million effective April 1, 2009.

*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%. In August 2008, PacifiCorp filed with the WUTC an all-party settlement agreement in which the parties agreed to an overall rate increase of $20 million, or 9%. The settlement was approved by the WUTC in October 2008 with the new rates effective October 15, 2008. The increase is composed of an $18 million increase to base rates, as well as a $2 million annual surcharge for approximately three years related to recovery of higher power costs incurred in 2005 due to poor hydroelectric conditions. PacifiCorp agreed to drop the current proposal for a generation cost adjustment mechanism and further committed not to propose such a mechanism in the next general rate case.

In February 2009, PacifiCorp filed a general rate case with the WUTC for an annual increase of $39 million, or an average price increase of 15%. The expected effective date for the rate change is January 11, 2010. The filing includes a request to begin collection of a deferral for costs associated with the 520-MW Chehalis natural gas-fired generating plant prior to its inclusion in rate base beginning in January 2010. The associated costs are estimated at $15 million. PacifiCorp has proposed to recover these costs through an extension in the hydroelectric deferral mechanism and thereby not affecting current customer rates.

*Idaho*

In September 2008, PacifiCorp filed a general rate case with the IPUC for an annual increase of $6 million, or an average price increase of 4%. The increase is primarily due to increased capital spending and net power costs. If approved, the new rates will become effective April 18, 2009. In February 2009, a settlement signed by PacifiCorp, the IPUC staff and intervening parties was filed with the IPUC resolving all issues in the 2008 general rate case. The agreement stipulates a $4 million increase, or 3% average rate increase, for non-contract retail customers in Idaho. As part of the stipulation, intervening parties acknowledged the following: PacifiCorp's acquisition of the Chehalis, Washington plant was prudent and the investment should be included in PacifiCorp's revenue requirement; PacifiCorp has demonstrated that its demand-side management programs are prudent; and a base level of net power costs is established for any future energy cost adjustment mechanism calculations if a mechanism is adopted in Idaho. In February 2009, parties to the stipulation filed supporting testimony recommending the IPUC approve the stipulation as filed. Public hearings were held in March 2009 for the IPUC to hear evidence in support of the settlement and associated price increase. A decision is pending.

In October 2008, PacifiCorp filed a request with the IPUC for approval of an ECAM to defer for later recovery in rates the difference between base net power costs set during a general rate case and actual net power costs incurred by PacifiCorp. If approved, PacifiCorp would file an application with the IPUC annually to adjust the ECAM surcharge rate to refund or collect the ECAM deferred balance from the end of the prior calendar year.

*California*

In 2008, PacifiCorp made filings with the CPUC requesting rate increases pursuant to the post-test year adjustment mechanism and the energy cost adjustment clause totaling $5 million, or average price increases totaling 6%. All requests were approved by the CPUC and the rates became effective various dates from August 23, 2008 through January 1, 2009.

In February 2009, PacifiCorp filed a post test year adjustment mechanism for major capital additions amounting to a rate adjustment of $1 million, or 2%. The filing included the addition of four major renewable resources; the 99-MW Seven Mile Hill, the 99-MW Glenrock, the 39-MW Glenrock III and the 99-MW Rolling Hills wind-powered generating facilities. The rates became effective March 19, 2009.

*Depreciation Rate Changes*

For a discussion of PacifiCorp's depreciation rate changes, refer to Note 3 of Notes to Financial Statements included in this Form No. 1.

## Environmental Regulation

PacifiCorp is subject to federal, state and local laws and regulations with regard to air and water quality, renewable portfolio standards ("RPS"), climate change, hazardous and solid waste disposal and other environmental matters and is subject to zoning and other regulation by local authorities. These laws and regulations are subject to a range of interpretation which may ultimately be resolved by the courts. 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 ("SIP") related to existing and new national ambient air quality standards. Rules issued by the Environmental Protection Agency (the "EPA") and certain states require substantial reductions in sulfur dioxide ("$SO_2$") and nitrogen oxide ("$NO_X$") 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" section 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" section 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 13 of Notes to Financial Statements included in this Form No. 1 for additional information regarding environmental contingencies.

- The FERC oversees the relicensing of existing hydroelectric systems and is also responsible for the oversight and issuance of licenses for new construction of hydroelectric systems, dam safety inspections and environmental monitoring. Refer to Note 13 of Notes to Financial Statements included in this Form No. 1 for additional information regarding the relicensing of certain of PacifiCorp's existing hydroelectric generating facilities.

*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.

*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. A new, more stringent standard for fine particulate matter became effective in December 2006. This standard was appealed to the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit"). On February 24, 2009, the D.C. Circuit ruled that the EPA had failed to adequately explain why the annual fine particulate matter standard set at 15 micrograms per cubic meter was sufficiently protective of public health and remanded the rule for further review of the standard. The existing rule will remain in place until the EPA takes further action. Air quality modeling and preliminary air quality monitoring data indicate 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.

In March 2008, the EPA issued final rules to strengthen the national ambient air quality standard for ground level ozone, lowering the standard to 0.075 parts per million from 0.08 parts per million. States have until March 2009 to characterize their attainment status, and the EPA's determinations regarding non-attainment will be made by March 2010 with SIPs due in 2013. Until the EPA makes its final attainment designations, the impact of any new standards on PacifiCorp will not be known.

*Regulated Air Pollutants*

In 2005, the EPA promulgated the Clean Air Mercury Rule ("CAMR") which would have regulated mercury emissions from coal-fired generating facilities through the use of a cap-and-trade system beginning in 2010, with reductions of approximately 70% when fully implemented in 2018. The CAMR was overturned by the United States Court of Appeals for the District of Columbia Circuit in February 2008. The EPA petitioned the United States Supreme Court for review of the lower court's decision in October 2008. On February 6, 2009, the EPA withdrew its petition for review before the United States Supreme Court and on February 23, 2009, the Supreme Court dismissed the petition. The EPA has indicated it plans to propose a new mercury rule that will require coal-fired generating facilities to utilize Maximum Achievable Control Technology, rather than a cap-and-trade mechanism, to reduce mercury emissions. As a result, PacifiCorp's coal-fired generating facilities may be required to install controls to reduce mercury emissions at each of its facilities rather than making cost-effective mercury emission reductions through a combination of controls and allowances. Depending on the scope and timing of these reduction requirements, as well as the availability and effectiveness of controls, the new rules could impose additional costs on PacifiCorp for control of mercury emissions above the costs anticipated under the CAMR.

The emissions reductions could be made more stringent by current or future regulatory and legislative proposals at the federal or state levels that would result in significant reductions of $SO_2$, $NO_X$ and mercury, as well as carbon dioxide and other gases that may affect global climate change.

*Regional Haze*

The EPA has initiated a regional haze program intended to improve visibility at specific federally protected areas. Some of PacifiCorp's generating facilities meet the threshold applicability criteria under the Clean Air Visibility Rules. In accordance with the federal requirements, states were required to submit SIPs 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 SIP and is continuing to review the planned emission reductions at PacifiCorp's Wyoming generating facilities. Utah submitted its SIP and suggested that the emission reduction projects planned by PacifiCorp are sufficient to meet its initial emission reduction requirements. In January 2009, the EPA made a finding that 37 states, including Wyoming, had failed to file a SIP that met some or all of the basic program requirements under the regional haze program. As a result, Wyoming has two years from January 2009 to file and obtain EPA approval of a SIP that meets all of the regional haze program requirements or the state will be subject to a federal implementation plan, with the EPA administering the regional haze program. 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 SIPs have been submitted or that the timing of the installation of planned controls could be changed.

*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 fines and other sanctions and remedies, including requiring installation of enhanced pollution controls and funding supplemental environmental projects.

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 facilities. Between 2001 and 2003, PacifiCorp responded to requests for information relating to its capital projects at its generating facilities and has been engaged in periodic discussions with the EPA over several years regarding PacifiCorp's historical projects and their compliance with NSR and PSD provisions. 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 generating facility, when combined with a modification (i.e., a physical or operational change), may trigger NSR permitting. PacifiCorp cannot predict the outcome of its discussions with the EPA at this time; however, PacifiCorp could be required to install additional emissions controls, and incur additional costs and penalties, in the event it is determined that PacifiCorp's historical projects did not meet all regulatory requirements.

Numerous changes have been proposed to the NSR rules and regulations over the last several years. These changes, withdrawals of proposed changes, differing interpretations by the EPA and the courts, and the recent change in administration, create risk and uncertainty for regulated entities in complying with NSR requirements when permitting new projects and installing emission controls at existing facilities. PacifiCorp monitors these changes and interpretations to ensure permitting activities are conducted in accordance with the applicable requirements.

*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 that 3% of retail sales by January 2012 through 2015, 9% of retail sales by January 2016 through 2019 and 15% of retail sales by January 2020 be supplied by qualified renewable resources. 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.

In June 2007, the Oregon Renewable Energy Act (the "OREA") was adopted, providing a comprehensive renewable energy policy for Oregon. Subject to certain exemptions and cost limitations established in the OREA, 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 OREA, 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 generating 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.

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. In May 2008, PacifiCorp and other small multi-jurisdictional utilities ("SMJU") received further guidance from the CPUC on the treatment of SMJUs in the California RPS program. In August 2008, concurrent with its annual RPS compliance filing, PacifiCorp, joined by another SMJU, filed a Joint Motion for Review of the decision, including banking of RPS procurement made while it awaited further guidance from the CPUC on the treatment of SMJUs during the 2004-2006 period. PacifiCorp noted among other things on this filing that its interpretation is consistent with the CPUC guidance and best serves the interests of its customers by recognizing past, good faith efforts to comply with California's RPS program beginning January 2004. PacifiCorp is currently awaiting the CPUC's response to the Joint Motion for Review. 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's governor signed Utah Senate Bill 202, Energy Resource and Carbon Emission Reduction Initiative. Among other things, this law provides that, beginning in the year 2025, 20% of adjusted retail electric sales of all Utah utilities be supplied by renewable energy, if it is cost effective. Retail electric sales will be adjusted by deducting the amount of generation from sources that produce zero or reduced carbon emissions, and for sales avoided as a result of energy efficiency and demand-side management programs. Qualifying renewable energy sources can be located anywhere in the WECC areas and renewable energy credits can be used. PacifiCorp expects to be able to recover its costs of complying with the law, either through rate cases or adjustment mechanisms.

*Climate Change*

As a result of increased attention to global climate change in the United States, there are significant future environmental regulations under consideration to increase the deployment of clean energy technologies and regulate emissions of greenhouse gas at the state, regional and federal levels. Congress and federal policy makers are considering climate change legislation and a variety of national climate change policies. President Obama has expressed support for an economy-wide greenhouse gas cap-and-trade program that would reduce emissions 80% below 1990 levels by 2050. Alternatively, or in conjunction with a cap, policy makers have discussed the possibility of imposing a tax on greenhouse gas emissions. Given the strong interest and support in reducing greenhouse gas emissions, PacifiCorp's electric generating facilities are likely to be subject to regulation of greenhouse gas emissions within the next several years.

In addition, nongovernmental organizations have become more active in initiating citizen suits under existing environmental and other laws and the EPA issued an advanced notice of proposed rulemaking in 2008 to consider issues associated with regulating greenhouse gas emissions under the Clean Air Act. The United States Supreme Court has ruled that the EPA has the authority under the Clean Air Act to regulate emissions of greenhouse gases from motor vehicles and that the EPA must make a determination relating to the danger posed by greenhouse gas emissions. 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 generating facilities 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 that are expected to impact PacifiCorp, including:

- The Western Regional Climate Action Initiative ("Western Climate Initiative"), a comprehensive regional effort to reduce greenhouse gas emissions by 15% below 2005 levels by 2020 through a cap-and-trade program that includes the electricity sector. The Western Climate Initiative includes the states of Arizona, California, Montana, New Mexico, Oregon, Utah and Washington and the provinces of British Columbia, Manitoba, Ontario and Quebec. The state and provincial partners have agreed to begin reporting greenhouse gas emissions in 2011 for emissions that occur in 2010. The first phase of the cap-and-trade program will begin in January 2012.

- 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-fired generating 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.

In addition to pending legislative proposals to regulate greenhouse gas emissions, in July 2008, the EPA issued an advance notice of proposed rulemaking presenting information relevant to, and soliciting public comment on, how to respond to the United States Supreme Court's decision in *Massachusetts v. EPA*, in which the United States Supreme Court ruled that the Clean Air Act authorizes regulation of greenhouses gases because they meet the definition of an air pollutant under the Clean Air Act, given the potential ramifications of a decision to regulate such emissions under the existing Clean Air Act framework.

PacifiCorp is currently subject to specific greenhouse gas-related requirements, including mandatory greenhouse gas reporting requirements in California, Washington and Oregon. California, Washington and Oregon also require the consideration of greenhouse gas emissions in new resource decisions through the establishment of greenhouse gas emissions performance standards and the requirement for mitigation of greenhouse gas emissions in conjunction with the addition of new emitting resources.

PacifiCorp believes in implementing public policy to address climate change in a manner that informs all constituents of cost ramifications and attempts to minimize such costs. PacifiCorp believes that research and development must be undertaken on a large scale and in a coordinated manner to obtain technologies that reduce carbon emissions while still providing reasonably priced energy and that the development and deployment of low-carbon electricity technologies must precede the imposition of significant emission reduction requirements or taxes or fees on emissions. PacifiCorp continues to add renewable and low-carbon electric capacity to its generation portfolio in an effort to reduce the carbon intensity of its generating capacity. From 2005 to 2008, through the addition of lower-carbon and renewable generation resources, PacifiCorp reduced the $CO_2$ intensity of its electricity generation portfolio by 11% while increasing the number of megawatt hours ("MWh") generated by 17%. In addition, PacifiCorp has engaged in several voluntary programs designed to reduce or avoid greenhouse gas emissions, including the EPA's sulfur hexafluoride reduction program, refrigerator recycling programs and the EPA landfill methane outreach program. PacifiCorp is a member of the California Climate Action Registry and The Climate Registry, under which it reports and certifies its greenhouse gas emissions.

Climate change may cause physical and financial risk through, among other things, sea level rise, changes in precipitation and extreme weather events. Energy needs may increase or decrease, based on overall changes in weather. Availability of resources to generate electricity, such as water for hydroelectric production and cooling purposes, may also be impacted by climate change and could influence PacifiCorp's existing and future electricity generation portfolio. These issues may have a direct impact on the costs of electricity production and increase the price paid by customers for electricity.

Legislative and regulatory responses to climate change have the potential to create financial risk. Adoption of early and stringent limits on greenhouse gas emissions could significantly adversely impact PacifiCorp's current and future fossil-fueled facilities, and therefore, its financial results. To the extent that PacifiCorp is not allowed by its regulators or cannot otherwise recover the costs incurred to comply with climate change requirements, these requirements could have a material adverse impact on PacifiCorp's financial results. Costs of compliance with environmental and other regulatory requirements are historically recovered in rates but risk regulatory lag. Although PacifiCorp does not make policy and does not take a position on the scientific aspects of climate change, it supports an informed dialogue on climate change and intends to implement actions to comply with any new legislation or regulation. 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 adversely impact PacifiCorp's current and future fossil-fueled generating facilities, and, therefore, its financial results.

*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 per 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 Court of Appeals' decision. The United States Supreme Court will consider whether Section 316(b) of the Clean Water Act authorizes the EPA to compare costs with benefits in determining "best technology available for minimizing adverse environmental impact" of cooling water intake solutions. Compliance and the potential costs of compliance, therefore, cannot be ascertained until such time as the United States Supreme Court's decision is rendered or further action is taken by the EPA. Currently, PacifiCorp's Dave Johnston plant exceeds the 50 million gallons of water per day intake threshold. In the event that PacifiCorp's existing intake structures require modification or alternative technology required by new rules, expenditures to comply with these requirements could be significant.

*Ash Disposal*

In December 2008, an ash impoundment dike at the Tennessee Valley Authority's Kingston power plant collapsed after heavy rain, releasing a significant amount of fly ash, bottom ash, coal combustion byproducts and water to the surrounding area. In light of this incident, federal and state officials have called for greater regulation of coal combustion storage and disposal. PacifiCorp operates coal ash impoundments and, in January 2008, voluntarily committed under an industry action plan to disposal restrictions, monitoring and reporting of coal combustion products that exceed requirements under current law. These ash impoundments could be impacted by additional regulation and could pose additional costs associated with ash management and disposal activities at PacifiCorp's coal-fired generating facilities. The impact of any new regulations on coal combustion products cannot be determined at this time.

## Future Generation and Conservation

*Integrated Resource Plan*

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. PacifiCorp files its IRP on a biennial basis.

In May 2007, PacifiCorp released its 2007 IRP, which identified a need for approximately 3,171 MW of additional resources by summer 2016 to satisfy the difference between projected retail load obligations and owned or contracted 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 owned or contracted resources.

In June and August 2008, PacifiCorp submitted to the state regulatory commissions a 2007 IRP update report reflecting revised planning assumptions. The need for additional resources by 2016 was essentially unchanged at 3,202 MW. Relative to the initial 2007 IRP, the planned resources to meet this need include a heavier reliance on energy efficiency measures. This need was reduced by 509 MW due to the September 2008 acquisition of the Chehalis plant. PacifiCorp's 2008 IRP is scheduled to be filed in Spring 2009, which will take into account recent declines in load and growth expectations.

*Requests for Proposal*

PacifiCorp has issued a series of separate requests for proposal ("RFPs"), each of which focuses on a specific category of resources consistent with the IRP. The IRP and the RFPs 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 RFPs with the UPSC, the OPUC and the WUTC prior to issuance to the market.

In February 2007, PacifiCorp filed a modified 2012 RFP (the "2012 RFP") in Utah for up to 1,700 MW of additional resources to become available beginning in 2012 through 2014. The 2012 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 generating facilities to power purchase agreements. Due to lack of cost effective bids, the 2012 RFP did not result in any new resources.

In January 2008, PacifiCorp issued to the market a renewable resources RFP for resources less than 100 MW, or greater than 100 MW for a power purchase agreement with a term of less than five years, to become available no later than December 2009. In September 2008, PacifiCorp executed a power purchase agreement to purchase the entire output of the proposed 99-MW Three Buttes wind-powered generating plant located in Wyoming. The generation of the energy and associated renewable energy credits under this agreement are expected to commence in December 2009 and continue for a period of 20 years.

In February 2008, PacifiCorp filed an all-source 2008 RFP (the "2008 RFP") with the UPSC and the OPUC for base-load, intermediate or third quarter summer peaking products to be delivered into PacifiCorp's system. The 2008 RFP seeks up to 2,000 MW of resources to become available beginning in 2012 through 2016. The 2008 RFP was approved by the OPUC and the UPSC and subsequently issued to the market in October 2008. Proposals were received from the market in December 2008. The proposals were evaluated and resulted in no cost effective proposals. As a result, the 2008 RFP was suspended and is expected to be reissued during 2009.

In April 2008, PacifiCorp filed its draft 2008R-1 renewable resources RFP (the "2008R-1 RFP") with the OPUC. The 2008R-1 RFP is a 500 MW request for renewable generation projects, with no single resource greater than 300 MW and on-line dates no later than December 31, 2011. The 2008R-1 RFP was approved by the OPUC in September 2008. Single renewable resource requests under 300 MW do not require approval from the UPSC. The 2008R-1 RFP was issued to the market in October 2008. Proposals were received from the market in December 2008 followed by an amendment issued in January 2009 to include new and updated proposals that were received in February 2009 which are being evaluated.

*Demand-side Management*

PacifiCorp has provided a comprehensive set of demand-side management programs to its customers since the 1970s. The programs are designed to reduce energy consumption and more effectively manage when energy is used, including management of seasonal peak loads. Current programs offer services to customers such as energy engineering audits and information on how to improve the efficiency of their homes and businesses. To assist customers in investing in energy efficiency, PacifiCorp offers rebates or incentives encouraging the purchase and installation of high-efficiency equipment such as lighting, heating and cooling equipment, weatherization, motors, process equipment and systems, as well as incentives for efficient construction. Incentives are also paid to solicit participation in load management programs by residential, business and agricultural customers through programs such as PacifiCorp's residential and small commercial air conditioner load control program and irrigation equipment load control programs. Subject to random prudence reviews, state regulations allow for contemporaneous recovery of costs incurred for retail customer demand-side management programs and services through state-specific energy efficiency service charges paid by all retail electric customers. In addition to these retail customer demand-side management programs, PacifiCorp has load curtailment contracts with a number of large industrial customers that deliver up to 342 MW of load reduction when needed. Recovery for the costs associated with the large industrial load management program is determined through PacifiCorp's general rate case process. In 2008, $77 million was expended on the demand-side management programs in PacifiCorp's six-state service area, resulting in an estimated 395,000 MWh of first-year energy savings and 338 MW of peak load management. Total demand-side load available for control in 2008, including both load management from the large industrial curtailment contracts and retail customer demand-side management programs, was approximately 680 MW.

## Credit Ratings

Debt and preferred securities of PacifiCorp are rated by nationally recognized credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of PacifiCorp's ability to, in general, meet the obligations of its issued debt or preferred securities. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time. PacifiCorp's credit ratings at March 31, 2009 were as follows:

| | Moody's | Standard & Poor's |
|---|---|---|
| Issuer/Corporate | Baa1 | A- |
| Senior secured debt | A3 | A |
| Senior unsecured debt | Baa1 | A- |
| Preferred stock | Baa3 | BBB |
| Commercial paper | P-2 | A-2 |
| Outlook | Stable | Stable |

PacifiCorp has no credit rating-downgrade triggers that would accelerate the maturity dates of outstanding debt and a change in ratings is not an event of default under applicable debt instruments. PacifiCorp's unsecured revolving credit facilities do not require the maintenance of a minimum credit rating level in order to draw upon their availability. However, commitment fees and interest rates under the credit facilities are tied to credit ratings and increase or decrease when the ratings change. A ratings downgrade could also increase the future cost of commercial paper, short- and long-term debt issuances or new credit facilities. Certain authorizations or exemptions by regulatory commissions for the issuance of securities are valid as long as PacifiCorp maintains investment grade ratings on senior secured debt. A downgrade below that level would necessitate new regulatory applications and approvals.

A change to PacifiCorp's credit rating could result in the requirement to post cash collateral, letters of credit or other similar credit support under certain agreements related to its procurement or sale of electricity, natural gas, coal and other supplies. In accordance with industry practice, PacifiCorp's agreements may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed certain ratings-dependent threshold levels, or provide the right for counterparties to demand "adequate assurances" in the event of a material adverse change in PacifiCorp's creditworthiness. As of December 31, 2008, PacifiCorp's credit ratings from the three recognized credit rating agencies were investment grade; however, if the ratings fell one rating below investment grade, PacifiCorp's collateral requirements would increase by approximately $356 million. Additional collateral requirements would be necessary if ratings fell further than one rating below investment grade. PacifiCorp's collateral requirements could fluctuate considerably due to seasonality, market price volatility, a loss of key PacifiCorp generating facilities or other related factors.

**Sunnyside Power Purchase Agreement**

PacifiCorp and Sunnyside Cogeneration Associates ("SCA") amended their 1987 power purchase agreement, which was approved by the UPSC in April 2008 and became effective in May 2008. As a result of the amendment, the agreement qualifies as a capital lease. The agreement requires PacifiCorp to purchase up to 53 MW of capacity and energy from the SCA's coal-fired generating facility. The amendment provides a new method for determining the avoided energy costs paid to SCA by PacifiCorp. The amendment also puts into place annual floor and ceiling prices that are applicable to the energy price. The original agreement end date remains as August 2023 with a renewal option of additional five-year periods. Minimum lease payment obligations are based on a minimum rate per megawatt-hour. PacifiCorp's minimum lease payments under this agreement will be $5 million for the four years ending December 31, 2012; $5 million for the four years ending December 31, 2016; $5 million for the four years ending December 31, 2020; and $5 million for the three years ending December 31, 2023.

**ITEM 13.**

**Officer & Director Changes**

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.

Douglas K. Stuver was elected 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.**

Not applicable.

Deloitte.

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# INDEPENDENT AUDITORS' REPORT

PacifiCorp
Portland, Oregon

We have audited the balance sheet — regulatory basis of PacifiCorp (the "Company") as of December 31, 2008, and the related statements of income — regulatory basis; retained earnings — regulatory basis; cash flows — regulatory basis, and accumulated other comprehensive income, comprehensive income, and hedging activities — regulatory basis for the year ended December 31, 2008, 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 the Company as of December 31, 2008, and the results of its operations and its cash flows for the year ended December 31, 2008, 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 the Company 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, 2009 (March 31, 2009 as to the Rate Matters section of Note 5)

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

| Line No. | Title of Account (a) | Ref. Page No. (b) | Current Year End of Quarter/Year Balance (c) | Prior Year End Balance 12/31 (d) |
|---|---|---|---|---|
| 1 | **UTILITY PLANT** | | | |
| 2 | Utility Plant (101-106, 114) | 200-201 | 18,462,953,925 | 16,637,482,510 |
| 3 | Construction Work in Progress (107) | 200-201 | 1,208,785,536 | 941,818,776 |
| 4 | TOTAL Utility Plant (Enter Total of lines 2 and 3) | | 19,671,739,461 | 17,579,301,286 |
| 5 | (Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115) | 200-201 | 6,848,927,351 | 6,691,765,903 |
| 6 | Net Utility Plant (Enter Total of line 4 less 5) | | 12,822,812,110 | 10,887,535,383 |
| 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) | | 12,822,812,110 | 10,887,535,383 |
| 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) | | 9,497,834 | 9,436,375 |
| 19 | (Less) Accum. Prov. for Depr. and Amort. (122) | | 1,455,833 | 1,396,066 |
| 20 | Investments in Associated Companies (123) | | 9,031,958 | 7,637,258 |
| 21 | Investment in Subsidiary Companies (123.1) | 224-225 | 171,510,195 | 149,005,037 |
| 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) | | 85,601,343 | 87,106,834 |
| 25 | Sinking Funds (125) | | 0 | 0 |
| 26 | Depreciation Fund (126) | | 0 | 0 |
| 27 | Amortization Fund - Federal (127) | | 0 | 0 |
| 28 | Other Special Funds (128) | | 8,081,370 | 9,530,018 |
| 29 | Special Funds (Non Major Only) (129) | | 0 | 0 |
| 30 | Long-Term Portion of Derivative Assets (175) | | 86,579,549 | 215,055,123 |
| 31 | Long-Term Portion of Derivative Assets – Hedges (176) | | 0 | 0 |
| 32 | TOTAL Other Property and Investments (Lines 18-21 and 23-31) | | 368,846,416 | 476,374,579 |
| 33 | **CURRENT AND ACCRUED ASSETS** | | | |
| 34 | Cash and Working Funds (Non-major Only) (130) | | 0 | 0 |
| 35 | Cash (131) | | 15,725,712 | 10,512,273 |
| 36 | Special Deposits (132-134) | | 2,048,982 | 6,256,766 |
| 37 | Working Fund (135) | | 2,020 | 2,670 |
| 38 | Temporary Cash Investments (136) | | 3,937,516 | 182,317,755 |
| 39 | Notes Receivable (141) | | 270,949 | 616,766 |
| 40 | Customer Accounts Receivable (142) | | 346,007,077 | 373,257,825 |
| 41 | Other Accounts Receivable (143) | | 43,610,380 | 15,687,039 |
| 42 | (Less) Accum. Prov. for Uncollectible Acct.-Credit (144) | | 8,679,145 | 6,551,765 |
| 43 | Notes Receivable from Associated Companies (145) | | 20,797,545 | 25,975,115 |
| 44 | Accounts Receivable from Assoc. Companies (146) | | 8,447,228 | 12,144,713 |
| 45 | Fuel Stock (151) | 227 | 136,802,882 | 98,334,182 |
| 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 | 170,075,369 | 150,050,022 |
| 49 | Merchandise (155) | 227 | 0 | 0 |
| 50 | Other Materials and Supplies (156) | 227 | 0 | 0 |
| 51 | Nuclear Materials Held for Sale (157) | 202-203/227 | 0 | 0 |
| 52 | Allowances (158.1 and 158.2) | 228-229 | 0 | 0 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

| Line No. | Title of Account<br>(a) | Ref. Page No.<br>(b) | Current Year End of Quarter/Year Balance<br>(c) | Prior Year End Balance 12/31<br>(d) |
|---|---|---|---|---|
| 53 | (Less) Noncurrent Portion of Allowances | | 0 | 0 |
| 54 | Stores Expense Undistributed (163) | 227 | 0 | 0 |
| 55 | Gas Stored Underground - Current (164.1) | | 0 | 0 |
| 56 | Liquefied Natural Gas Stored and Held for Processing (164.2-164.3) | | 0 | 0 |
| 57 | Prepayments (165) | | 84,769,212 | 79,684,518 |
| 58 | Advances for Gas (166-167) | | 0 | 0 |
| 59 | Interest and Dividends Receivable (171) | | 28,102 | 13,245,222 |
| 60 | Rents Receivable (172) | | 2,172,050 | 3,189,547 |
| 61 | Accrued Utility Revenues (173) | | 210,896,000 | 192,299,000 |
| 62 | Miscellaneous Current and Accrued Assets (174) | | 8,854,407 | 11,238,653 |
| 63 | Derivative Instrument Assets (175) | | 260,256,083 | 357,980,420 |
| 64 | (Less) Long-Term Portion of Derivative Instrument Assets (175) | | 86,579,549 | 215,055,123 |
| 65 | Derivative Instrument Assets - Hedges (176) | | 0 | 0 |
| 66 | (Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176 | | 0 | 0 |
| 67 | Total Current and Accrued Assets (Lines 34 through 66) | | 1,219,442,820 | 1,311,185,598 |
| 68 | **DEFERRED DEBITS** | | | |
| 69 | Unamortized Debt Expenses (181) | | 30,017,721 | 27,166,066 |
| 70 | Extraordinary Property Losses (182.1) | 230 | 0 | 0 |
| 71 | Unrecovered Plant and Regulatory Study Costs (182.2) | 230 | 10,439,101 | 15,589,069 |
| 72 | Other Regulatory Assets (182.3) | 232 | 1,626,353,730 | 1,081,739,789 |
| 73 | Prelim. Survey and Investigation Charges (Electric) (183) | | 1,091,392 | 0 |
| 74 | Preliminary Natural Gas Survey and Investigation Charges 183.1) | | 0 | 0 |
| 75 | Other Preliminary Survey and Investigation Charges (183.2) | | 0 | 0 |
| 76 | Clearing Accounts (184) | | 0 | 0 |
| 77 | Temporary Facilities (185) | | 88,829 | 115,300 |
| 78 | Miscellaneous Deferred Debits (186) | 233 | 72,806,094 | 52,116,892 |
| 79 | Def. Losses from Disposition of Utility Plt. (187) | | 0 | 0 |
| 80 | Research, Devel. and Demonstration Expend. (188) | 352-353 | 0 | 0 |
| 81 | Unamortized Loss on Reaquired Debt (189) | | 16,563,180 | 20,786,394 |
| 82 | Accumulated Deferred Income Taxes (190) | 234 | 586,940,125 | 432,328,560 |
| 83 | Unrecovered Purchased Gas Costs (191) | | 0 | 0 |
| 84 | Total Deferred Debits (lines 69 through 83) | | 2,344,300,172 | 1,629,842,070 |
| 85 | TOTAL ASSETS (lines 14-16, 32, 67, and 84) | | 16,755,401,518 | 14,304,937,630 |

***Schedule Page: 110 Line No.: 57 Column: c***

At December 31, 2008, account 165 Prepayments included $42.2 million in income taxes receivable due from MidAmerican Energy Holdings Company, PacifiCorp's indirect parent company.

***Schedule Page: 110 Line No.: 57 Column: d***

At December 31, 2007, account 165 Prepayments included $22.2 million in income taxes receivable due from MidAmerican Energy Holdings Company, PacifiCorp's indirect parent company.

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**(Next Page is 112)**

| Name of Respondent | This Report is: | Date of Report (mo, da, yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Rresubmission | 03/31/2009 | end of 2008/Q4 |

## COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

| Line No. | Title of Account (a) | Ref. Page No. (b) | Current Year End of Quarter/Year Balance (c) | Prior Year End Balance 12/31 (d) |
|---|---|---|---|---|
| 1 | PROPRIETARY CAPITAL | | | |
| 2 | Common Stock Issued (201) | 250-251 | 3,417,945,896 | 3,417,945,896 |
| 3 | Preferred Stock Issued (204) | 250-251 | 41,463,300 | 41,463,300 |
| 4 | Capital Stock Subscribed (202, 205) | 252 | 0 | 0 |
| 5 | Stock Liability for Conversion (203, 206) | 252 | 0 | 0 |
| 6 | Premium on Capital Stock (207) | 252 | 0 | 0 |
| 7 | Other Paid-In Capital (208-211) | 253 | 877,063,956 | 427,063,956 |
| 8 | Installments Received on Capital Stock (212) | 252 | 0 | 0 |
| 9 | (Less) Discount on Capital Stock (213) | 254 | 0 | 0 |
| 10 | (Less) Capital Stock Expense (214) | 254 | 41,288,207 | 41,288,207 |
| 11 | Retained Earnings (215, 215.1, 216) | 118-119 | 1,687,760,382 | 1,231,878,766 |
| 12 | Unappropriated Undistributed Subsidiary Earnings (216.1) | 118-119 | 6,508,778 | 7,557,544 |
| 13 | (Less) Reaquired Capital Stock (217) | 250-251 | 0 | 0 |
| 14 | Noncorporate Proprietorship (Non-major only) (218) | | 0 | 0 |
| 15 | Accumulated Other Comprehensive Income (219) | 122(a)(b) | -2,550,680 | -3,516,384 |
| 16 | Total Proprietary Capital (lines 2 through 15) | | 5,986,903,425 | 5,081,104,871 |
| 17 | LONG-TERM DEBT | | | |
| 18 | Bonds (221) | 256-257 | 5,510,797,000 | 5,123,205,000 |
| 19 | (Less) Reaquired Bonds (222) | 256-257 | 0 | 0 |
| 20 | Advances from Associated Companies (223) | 256-257 | 0 | 0 |
| 21 | Other Long-Term Debt (224) | 256-257 | 0 | 0 |
| 22 | Unamortized Premium on Long-Term Debt (225) | | 38,281 | 40,999 |
| 23 | (Less) Unamortized Discount on Long-Term Debt-Debit (226) | | 7,963,911 | 6,014,592 |
| 24 | Total Long-Term Debt (lines 18 through 23) | | 5,502,871,370 | 5,117,231,407 |
| 25 | OTHER NONCURRENT LIABILITIES | | | |
| 26 | Obligations Under Capital Leases - Noncurrent (227) | | 59,390,328 | 47,949,276 |
| 27 | Accumulated Provision for Property Insurance (228.1) | | 0 | 0 |
| 28 | Accumulated Provision for Injuries and Damages (228.2) | | 8,501,565 | 6,054,192 |
| 29 | Accumulated Provision for Pensions and Benefits (228.3) | | 604,317,224 | 315,188,411 |
| 30 | Accumulated Miscellaneous Operating Provisions (228.4) | | 42,256,560 | 38,105,696 |
| 31 | Accumulated Provision for Rate Refunds (229) | | 0 | 0 |
| 32 | Long-Term Portion of Derivative Instrument Liabilities | | 490,202,449 | 496,923,540 |
| 33 | Long-Term Portion of Derivative Instrument Liabilities - Hedges | | 0 | 0 |
| 34 | Asset Retirement Obligations (230) | | 80,948,143 | 75,241,936 |
| 35 | Total Other Noncurrent Liabilities (lines 26 through 34) | | 1,285,616,269 | 979,463,051 |
| 36 | CURRENT AND ACCRUED LIABILITIES | | | |
| 37 | Notes Payable (231) | | 85,000,000 | 0 |
| 38 | Accounts Payable (232) | | 744,182,870 | 449,488,562 |
| 39 | Notes Payable to Associated Companies (233) | | 0 | 0 |
| 40 | Accounts Payable to Associated Companies (234) | | 17,383,942 | 11,007,508 |
| 41 | Customer Deposits (235) | | 21,919,032 | 21,686,771 |
| 42 | Taxes Accrued (236) | 262-263 | 28,648,482 | 20,901,699 |
| 43 | Interest Accrued (237) | | 88,654,332 | 86,897,114 |
| 44 | Dividends Declared (238) | | 520,947 | 520,947 |
| 45 | Matured Long-Term Debt (239) | | 0 | 0 |

| Name of Respondent | This Report is: | Date of Report (mo, da, yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Rresubmission | 03/31/2009 | end of 2008/Q4 |

## COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS) (continued)

| Line No. | Title of Account<br>(a) | Ref. Page No.<br>(b) | Current Year End of Quarter/Year Balance<br>(c) | Prior Year End Balance 12/31<br>(d) |
|---|---|---|---|---|
| 46 | Matured Interest (240) | | 0 | 0 |
| 47 | Tax Collections Payable (241) | | 14,388,665 | 13,034,927 |
| 48 | Miscellaneous Current and Accrued Liabilities (242) | | 67,406,951 | 76,018,366 |
| 49 | Obligations Under Capital Leases-Current (243) | | 5,768,004 | 1,428,748 |
| 50 | Derivative Instrument Liabilities (244) | | 620,548,360 | 613,992,765 |
| 51 | (Less) Long-Term Portion of Derivative Instrument Liabilities | | 490,202,449 | 496,923,540 |
| 52 | Derivative Instrument Liabilities - Hedges (245) | | 0 | 0 |
| 53 | (Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges | | 0 | 0 |
| 54 | Total Current and Accrued Liabilities (lines 37 through 53) | | 1,204,219,136 | 798,053,867 |
| 55 | DEFERRED CREDITS | | | |
| 56 | Customer Advances for Construction (252) | | 20,259,578 | 17,485,789 |
| 57 | Accumulated Deferred Investment Tax Credits (255) | 266-267 | 49,828,356 | 53,767,820 |
| 58 | Deferred Gains from Disposition of Utility Plant (256) | | 0 | 0 |
| 59 | Other Deferred Credits (253) | 269 | 42,762,022 | 59,527,962 |
| 60 | Other Regulatory Liabilities (254) | 278 | 76,456,654 | 71,343,435 |
| 61 | Unamortized Gain on Reaquired Debt (257) | | 0 | 0 |
| 62 | Accum. Deferred Income Taxes-Accel. Amort.(281) | 272-277 | 0 | 0 |
| 63 | Accum. Deferred Income Taxes-Other Property (282) | | 2,095,724,933 | 1,832,890,057 |
| 64 | Accum. Deferred Income Taxes-Other (283) | | 490,759,775 | 294,069,371 |
| 65 | Total Deferred Credits (lines 56 through 64) | | 2,775,791,318 | 2,329,084,434 |
| 66 | TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65) | | 16,755,401,518 | 14,304,937,630 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## STATEMENT OF INCOME

Quarterly

1. Enter in column (d) the balance for the reporting quarter and in column (e) the balance for the same three month period for the prior year.
2. Report in column (f) the quarter to date amounts for electric utility function; in column (h) the quarter to date amounts for gas utility, and in (j) the quarter to date amounts for other utility function for the current year quarter.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in (k) the quarter to date amounts for other utility function for the prior year quarter.
4. If additional columns are needed place them in a footnote.

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
8. Report data for lines 8, 10 and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.

| Line No. | Title of Account<br>(a) | (Ref.) Page No.<br>(b) | Total Current Year to Date Balance for Quarter/Year<br>(c) | Total Prior Year to Date Balance for Quarter/Year<br>(d) | Current 3 Months Ended Quarterly Only No 4th Quarter<br>(e) | Prior 3 Months Ended Quarterly Only No 4th Quarter<br>(f) |
|---|---|---|---|---|---|---|
| 1 | UTILITY OPERATING INCOME | | | | | |
| 2 | Operating Revenues (400) | 300-301 | 4,494,585,986 | 4,243,625,971 | | |
| 3 | Operating Expenses | | | | | |
| 4 | Operation Expenses (401) | 320-323 | 2,593,626,077 | 2,407,885,415 | | |
| 5 | Maintenance Expenses (402) | 320-323 | 374,652,182 | 378,009,826 | | |
| 6 | Depreciation Expense (403) | 336-337 | 416,636,387 | 418,496,844 | | |
| 7 | Depreciation Expense for Asset Retirement Costs (403.1) | 336-337 | | | | |
| 8 | Amort. & Depl. of Utility Plant (404-405) | 336-337 | 40,332,443 | 45,276,103 | | |
| 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) | | 5,107,035 | 2,452,562 | | |
| 11 | Amort. of Conversion Expenses (407) | | | | | |
| 12 | Regulatory Debits (407.3) | | 7,057,628 | 10,429,071 | | |
| 13 | (Less) Regulatory Credits (407.4) | | | | | |
| 14 | Taxes Other Than Income Taxes (408.1) | 262-263 | 112,424,490 | 101,472,747 | | |
| 15 | Income Taxes - Federal (409.1) | 262-263 | -83,683,183 | 125,610,768 | | |
| 16 | - Other (409.1) | 262-263 | -8,319,652 | 15,623,546 | | |
| 17 | Provision for Deferred Income Taxes (410.1) | 234, 272-277 | 669,322,953 | 425,065,057 | | |
| 18 | (Less) Provision for Deferred Income Taxes-Cr. (411.1) | 234, 272-277 | 356,785,266 | 366,448,712 | | |
| 19 | Investment Tax Credit Adj. - Net (411.4) | 266 | -1,874,204 | -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) | | 4,889,027 | 14,663,498 | | |
| 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) | | 3,769,087,216 | 3,548,834,222 | | |
| 26 | Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27 | | 725,498,770 | 694,791,749 | | |

## STATEMENT OF INCOME FOR THE YEAR (Continued)

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

| ELECTRIC UTILITY | | GAS UTILITY | | OTHER UTILITY | | |
|---|---|---|---|---|---|---|
| Current Year to Date (in dollars) (g) | Previous Year to Date (in dollars) (h) | Current Year to Date (in dollars) (i) | Previous Year to Date (in dollars) (j) | Current Year to Date (in dollars) (k) | Previous Year to Date (in dollars) (l) | Line No. |
| | | | | | | 1 |
| 4,494,585,986 | 4,243,625,971 | | | | | 2 |
| | | | | | | 3 |
| 2,593,626,077 | 2,407,885,415 | | | | | 4 |
| 374,652,182 | 378,009,826 | | | | | 5 |
| 416,636,387 | 418,496,844 | | | | | 6 |
| | | | | | | 7 |
| 40,332,443 | 45,276,103 | | | | | 8 |
| 5,479,353 | 5,479,353 | | | | | 9 |
| 5,107,035 | 2,452,562 | | | | | 10 |
| | | | | | | 11 |
| 7,057,628 | 10,429,071 | | | | | 12 |
| | | | | | | 13 |
| 112,424,490 | 101,472,747 | | | | | 14 |
| -83,683,183 | 125,610,768 | | | | | 15 |
| -8,319,652 | 15,623,546 | | | | | 16 |
| 669,322,953 | 425,065,057 | | | | | 17 |
| 356,785,266 | 366,448,712 | | | | | 18 |
| -1,874,204 | -5,854,860 | | | | | 19 |
| | | | | | | 20 |
| | | | | | | 21 |
| 4,889,027 | 14,663,498 | | | | | 22 |
| | | | | | | 23 |
| | | | | | | 24 |
| 3,769,087,216 | 3,548,834,222 | | | | | 25 |
| 725,498,770 | 694,791,749 | | | | | 26 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## STATEMENT OF INCOME FOR THE YEAR (continued)

| Line No. | Title of Account<br>(a) | (Ref.) Page No.<br>(b) | TOTAL<br>Current Year<br>(c) | TOTAL<br>Previous Year<br>(d) | Current 3 Months Ended Quarterly Only No 4th Quarter<br>(e) | Prior 3 Months Ended Quarterly Only No 4th Quarter<br>(f) |
|---|---|---|---|---|---|---|
| 27 | Net Utility Operating Income (Carried forward from page 114) | | 725,498,770 | 694,791,749 | | |
| 28 | Other Income and Deductions | | | | | |
| 29 | Other Income | | | | | |
| 30 | Nonutilty Operating Income | | | | | |
| 31 | Revenues From Merchandising, Jobbing and Contract Work (415) | | 2,278,244 | 2,760,357 | | |
| 32 | (Less) Costs and Exp. of Merchandising, Job. & Contract Work (416) | | 2,444,146 | 2,946,861 | | |
| 33 | Revenues From Nonutility Operations (417) | | 233,693 | 239,021 | | |
| 34 | (Less) Expenses of Nonutility Operations (417.1) | | 26,272 | 25,945 | | |
| 35 | Nonoperating Rental Income (418) | | 60,570 | 63,654 | | |
| 36 | Equity in Earnings of Subsidiary Companies (418.1) | 119 | -1,905,654 | 1,716,150 | | |
| 37 | Interest and Dividend Income (419) | | 10,637,009 | 13,913,812 | | |
| 38 | Allowance for Other Funds Used During Construction (419.1) | | 46,616,392 | 40,906,060 | | |
| 39 | Miscellaneous Nonoperating Income (421) | | 144,442,511 | 164,005,754 | | |
| 40 | Gain on Disposition of Property (421.1) | | 2,378,680 | 890,266 | | |
| 41 | TOTAL Other Income (Enter Total of lines 31 thru 40) | | 202,271,027 | 221,522,268 | | |
| 42 | Other Income Deductions | | | | | |
| 43 | Loss on Disposition of Property (421.2) | | 263,455 | 4,210,041 | | |
| 44 | Miscellaneous Amortization (425) | 340 | 1,165,477 | 1,118,623 | | |
| 45 | Donations (426.1) | 340 | 2,848,144 | 2,863,061 | | |
| 46 | Life Insurance (426.2) | | -2,259,327 | -4,961,276 | | |
| 47 | Penalties (426.3) | | 1,560,618 | 4,184,046 | | |
| 48 | Exp. for Certain Civic, Political & Related Activities (426.4) | | 1,265,718 | 1,147,711 | | |
| 49 | Other Deductions (426.5) | | 143,419,880 | 161,982,725 | | |
| 50 | TOTAL Other Income Deductions (Total of lines 43 thru 49) | | 148,263,965 | 170,544,931 | | |
| 51 | Taxes Applic. to Other Income and Deductions | | | | | |
| 52 | Taxes Other Than Income Taxes (408.2) | 262-263 | 238,746 | 223,659 | | |
| 53 | Income Taxes-Federal (409.2) | 262-263 | 20,014,193 | 18,941,072 | | |
| 54 | Income Taxes-Other (409.2) | 262-263 | 2,719,596 | 2,573,778 | | |
| 55 | Provision for Deferred Inc. Taxes (410.2) | 234, 272-277 | 146,049,815 | 58,876,813 | | |
| 56 | (Less) Provision for Deferred Income Taxes-Cr. (411.2) | 234, 272-277 | 146,944,899 | 59,117,957 | | |
| 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) | | 20,012,191 | 19,432,105 | | |
| 60 | Net Other Income and Deductions (Total of lines 41, 50, 59) | | 33,994,871 | 31,545,232 | | |
| 61 | Interest Charges | | | | | |
| 62 | Interest on Long-Term Debt (427) | | 313,572,989 | 278,731,910 | | |
| 63 | Amort. of Debt Disc. and Expense (428) | | 3,072,734 | 3,012,770 | | |
| 64 | Amortization of Loss on Reaquired Debt (428.1) | | 4,223,214 | 4,651,715 | | |
| 65 | (Less) Amort. of Premium on Debt-Credit (429) | | 2,718 | 2,718 | | |
| 66 | (Less) Amortization of Gain on Reaquired Debt-Credit (429.1) | | | 56,166 | | |
| 67 | Interest on Debt to Assoc. Companies (430) | 340 | | | | |
| 68 | Other Interest Expense (431) | 340 | 14,625,063 | 29,764,583 | | |
| 69 | (Less) Allowance for Borrowed Funds Used During Construction-Cr. (432) | | 34,280,545 | 28,653,980 | | |
| 70 | Net Interest Charges (Total of lines 62 thru 69) | | 301,210,737 | 287,448,114 | | |
| 71 | Income Before Extraordinary Items (Total of lines 27, 60 and 70) | | 458,282,904 | 438,888,867 | | |
| 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) | | 458,282,904 | 438,888,867 | | |

***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.

| | Years Ended December 31, 2008 | Years Ended December 31, 2007 |
|---|---|---|
| Vehicle Depreciation | $ 13,465,822 | $ 12,494,116 |

***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.

| | Years Ended December 31, 2008 | Years Ended December 31, 2007 |
|---|---|---|
| Payroll Tax Expense | $ 37,428,777 | $ 35,600,794 |

***Schedule Page: 114 Line No.: 15 Column: c***

The credit balance reported in current tax expense is primarily attributable to a provision-to-return true-up for the calendar year ended December 31, 2007 and to a provision for net operating loss (tax basis) and tax credit carrybacks for the calendar year ended December 31, 2008. PacifiCorp's net operating loss (tax basis) is primarily attributable to accelerated tax depreciation and tax bonus depreciation taken in excess of book depreciation.

***Schedule Page: 114 Line No.: 16 Column: c***

See footnote line 15, column C.

***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 | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## STATEMENT OF RETAINED EARNINGS

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

| Line No. | Item (a) | Contra Primary Account Affected (b) | Current Quarter/Year Year to Date Balance (c) | Previous Quarter/Year Year to Date Balance (d) |
|---|---|---|---|---|
| | UNAPPROPRIATED RETAINED EARNINGS (Account 216) | | | |
| 1 | Balance-Beginning of Period | | 1,228,302,955 | 779,888,925 |
| 2 | Changes | | | |
| 3 | Adjustments to Retained Earnings (Account 439) | | | |
| 4 | Adoption of FASB Interpretation No. 48 | 236 | | 13,325,103 |
| 5 | | | | |
| 6 | | | | |
| 7 | | | | |
| 8 | | | | |
| 9 | TOTAL Credits to Retained Earnings (Acct. 439) | | | 13,325,103 |
| 10 | Adoption of SFAS No. 158 measurement date provisions, net | | | |
| 11 | of tax of ($943,130) | 228.3 | -1,366,264 | |
| 12 | | | | |
| 13 | | | | |
| 14 | | | | |
| 15 | TOTAL Debits to Retained Earnings (Acct. 439) | | -1,366,264 | |
| 16 | Balance Transferred from Income (Account 433 less Account 418.1) | | 460,188,558 | 437,172,717 |
| 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 | | | | |
| 32 | | | | |
| 33 | | | | |
| 34 | | | | |
| 35 | | | | |
| 36 | TOTAL Dividends Declared-Common Stock (Acct. 438) | | | |
| 37 | Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings | | -856,888 | |
| 38 | Balance - End of Period (Total 1,9,15,16,22,29,36,37) | | 1,684,184,571 | 1,228,302,955 |
| | APPROPRIATED RETAINED EARNINGS (Account 215) | | | |
| 39 | | | | |
| 40 | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## STATEMENT OF RETAINED EARNINGS

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

| Line No. | Item (a) | Contra Primary Account Affected (b) | Current Quarter/Year Year to Date Balance (c) | Previous Quarter/Year Year to Date Balance (d) |
|---|---|---|---|---|
| 41 | | | | |
| 42 | | | | |
| 43 | | | | |
| 44 | | | | |
| 45 | TOTAL Appropriated Retained Earnings (Account 215) | | | |
| | APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1) | | | |
| 46 | TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1) | | 3,575,811 | 3,575,811 |
| 47 | TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46) | | 3,575,811 | 3,575,811 |
| 48 | TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1) | | 1,687,760,382 | 1,231,878,766 |
| | UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account | | | |
| | Report only on an Annual Basis, no Quarterly | | | |
| 49 | Balance-Beginning of Year (Debit or Credit) | | 7,557,544 | 5,841,394 |
| 50 | Equity in Earnings for Year (Credit) (Account 418.1) | | -1,905,654 | 1,716,150 |
| 51 | (Less) Dividends Received (Debit) | | | |
| 52 | Transfers from Unapprop. Retained Earnings (Account 216) | | 856,888 | |
| 53 | Balance-End of Year (Total lines 49 thru 52) | | 6,508,778 | 7,557,544 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## STATEMENT OF CASH FLOWS

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

| Line No. | Description (See Instruction No. 1 for Explanation of Codes)<br>(a) | Current Year to Date Quarter/Year<br>(b) | Previous Year to Date Quarter/Year<br>(c) |
|---|---|---|---|
| 1 | Net Cash Flow from Operating Activities: | | |
| 2 | Net Income (Line 78(c) on page 117) | 458,282,904 | 438,888,867 |
| 3 | Noncash Charges (Credits) to Income: | | |
| 4 | Depreciation and Depletion | 430,811,133 | 431,935,488 |
| 5 | Amortization: | 59,141,936 | 64,755,712 |
| 6 | | | |
| 7 | Unrealized (Gains)/Losses on Derivative Contracts | 61,572 | -1,661,541 |
| 8 | Deferred Income Taxes (Net) | 311,719,127 | 45,331,714 |
| 9 | Investment Tax Credit Adjustment (Net) | -3,939,464 | -7,920,120 |
| 10 | Net (Increase) Decrease in Receivables | 4,400,377 | -74,006,726 |
| 11 | Net (Increase) Decrease in Inventory | -57,076,891 | -36,421,476 |
| 12 | Net (Increase) Decrease in Allowances Inventory | | |
| 13 | Net Increase (Decrease) in Payables and Accrued Expenses | 7,685,336 | 47,887,940 |
| 14 | Net (Increase) Decrease in Other Regulatory Assets | -36,836,116 | -18,006,439 |
| 15 | Net Increase (Decrease) in Other Regulatory Liabilities | -2,020 | -27,468,274 |
| 16 | (Less) Allowance for Other Funds Used During Construction | 46,616,392 | 40,906,060 |
| 17 | (Less) Undistributed Earnings from Subsidiary Companies | -1,905,654 | 1,716,150 |
| 18 | Amounts Due To/From Affiliates, Net | -9,844,783 | 20,506,275 |
| 19 | Derivative Contract Assets/Liabilities, Net | -81,900,000 | 400,000 |
| 20 | Other Operating Activities: | -53,394,167 | -14,775,749 |
| 21 | | | |
| 22 | Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21) | 984,398,206 | 826,823,461 |
| 23 | | | |
| 24 | Cash Flows from Investment Activities: | | |
| 25 | Construction and Acquisition of Plant (including land): | | |
| 26 | Gross Additions to Utility Plant (less nuclear fuel) | -1,805,989,623 | -1,525,508,915 |
| 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 | -46,616,392 | -40,906,060 |
| 31 | Acquisitions, Net of Cash Acquired | -307,682,572 | |
| 32 | | | |
| 33 | | | |
| 34 | Cash Outflows for Plant (Total of lines 26 thru 33) | -2,067,055,803 | -1,484,602,855 |
| 35 | | | |
| 36 | Acquisition of Other Noncurrent Assets (d) | | |
| 37 | Proceeds from Disposal of Noncurrent Assets (d) | 3,012,032 | 2,685,689 |
| 38 | | | |
| 39 | Investments in and Advances to Assoc. and Subsidiary Companies | -10,417,000 | -22,349,232 |
| 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) | -9,698 | |
| 45 | Proceeds from Sales of Investment Securities (a) | | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## STATEMENT OF CASH FLOWS

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

| Line No. | Description (See Instruction No. 1 for Explanation of Codes)<br>(a) | Current Year to Date Quarter/Year<br>(b) | Previous Year to Date Quarter/Year<br>(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: | 4,988,593 | 13,017,394 |
| 54 | | | |
| 55 | | | |
| 56 | Net Cash Provided by (Used in) Investing Activities | | |
| 57 | Total of lines 34 thru 55) | -2,069,481,876 | -1,491,249,004 |
| 58 | | | |
| 59 | Cash Flows from Financing Activities: | | |
| 60 | Proceeds from Issuance of: | | |
| 61 | Long-Term Debt (b) | 792,126,293 | 1,193,405,452 |
| 62 | Preferred Stock | | |
| 63 | Common Stock | | |
| 64 | Equity Contribution | 450,000,000 | 200,000,000 |
| 65 | Reacquired Bonds | 216,470,000 | |
| 66 | Net Increase in Short-Term Debt (c) | 84,991,027 | |
| 67 | Other Financing Activities: | | 3,502,924 |
| 68 | | | |
| 69 | | | |
| 70 | Cash Provided by Outside Sources (Total 61 thru 69) | 1,543,587,320 | 1,396,908,376 |
| 71 | | | |
| 72 | Payments for Retirement of: | | |
| 73 | Long-term Debt (b) | -412,408,000 | -125,667,000 |
| 74 | Preferred Stock | | -37,500,000 |
| 75 | Common Stock | | |
| 76 | Other (provide details in footnote): | | |
| 77 | Repayment of Capital Lease Obligations | -709,310 | -1,254,709 |
| 78 | Net Decrease in Short-Term Debt (c) | | -397,251,666 |
| 79 | Reacquired Bonds | -216,470,000 | |
| 80 | Dividends on Preferred Stock | -2,083,790 | -2,083,790 |
| 81 | Dividends on Common Stock | | |
| 82 | Net Cash Provided by (Used in) Financing Activities | | |
| 83 | (Total of lines 70 thru 81) | 911,916,220 | 833,151,211 |
| 84 | | | |
| 85 | Net Increase (Decrease) in Cash and Cash Equivalents | | |
| 86 | (Total of lines 22,57 and 83) | -173,167,450 | 168,725,668 |
| 87 | | | |
| 88 | Cash and Cash Equivalents at Beginning of Period | 192,832,698 | 24,107,030 |
| 89 | | | |
| 90 | Cash and Cash Equivalents at End of period | 19,665,248 | 192,832,698 |

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

| | YTD 12/31/2008 | YTD 12/31/2007 | FERC Account |
|---|---|---|---|
| Amortization of Software Development & Other Intangibles | $ 40,332,443 | $ 45,276,103 | 404 |
| Amortization of Licensing/Hydro | 1,165,477 | 1,118,623 | 425 |
| Amortization of Electric Plant Acquisition Adjustment | 5,479,353 | 5,479,353 | 405 |
| Amortization of Regulatory Assets | 12,164,663 | 12,881,633 | 407 / 407.3 |
| | $ 59,141,936 | $ 64,755,712 | |

**Schedule Page: 120 Line No.: 20 Column: a**

| | YTD 12/31/2008 | YTD 12/31/2007 | FERC Account |
|---|---|---|---|
| Coal and Steam Depreciation & Depletion included in Cost of Fuel | $ 12,035,196 | $ 15,163,499 | 151 |
| PMI Equity Earnings included in Cost of Fuel | (8,910,812) | (6,808,915) | 151 |
| (Gain)/Loss on Sale of Property | (2,588,295) | 893,597 | 101/108 |
| Deferred Credits - Deferred Compensation | (2,125,011) | (6,385,866) | 253 |
| Accumulated Provision for Pension & Benefits | (42,626,647) | (19,781,800) | 228 |
| Write-Off of Assets Under Construction | 4,813,141 | 10,602,121 | 107 |
| BPA Prepaid Transmission | (7,488,000) | - | 186 |
| Accumulated Provision for Mining/Environ/Decom | (3,044,671) | (5,632,346) | 228 / 253 |
| Long-Term Notes Receivable | (2,357,519) | 2,125,634 | 124 / 186 |
| Other | (1,101,549) | (4,951,673) | Various |
| | $(53,394,167) | $(14,775,749) | |

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

| | YTD 12/31/2008 | YTD 12/31/2007 | FERC Account |
|---|---|---|---|
| Other Investments/Special Funds | $ 3,344,372 | $ 7,670,035 | 124 / 128 |
| Temporary Facilities | 26,471 | (78,766) | 185 |
| Restricted Cash | 1,617,750 | 5,426,125 | 128 / 134 |
| | $ 4,988,593 | $ 13,017,394 | |

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

| | YTD 12/31/2008 | YTD 12/31/2007 | FERC Account |
|---|---|---|---|
| Tax Benefit of Stock Options Exercised | $ - | $ 3,502,924 | 211 |

**Schedule Page: 120 Line No.: 74 Column: c**

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.

## NOTES TO FINANCIAL STATEMENTS

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

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

**PACIFICORP AND SUBSIDIARIES**
**NOTES TO FINANCIAL STATEMENTS**

## (1) Organization and Operations

PacifiCorp, which includes PacifiCorp and its subsidiaries, is a United States regulated electric 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, wind-powered and geothermal generating facilities, 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. PacifiCorp is subject to comprehensive state and federal regulation. PacifiCorp's subsidiaries support its electric utility operations by providing coal-mining services. PacifiCorp is an indirect subsidiary of MidAmerican Energy Holdings Company ("MEHC"), a holding company based in Des Moines, Iowa, owning subsidiaries that are principally engaged in energy businesses. MEHC 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:

*Investment 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 ("ARO") 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 accounting and reporting standards.

*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 under the FERC accounting and 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 under the FERC reporting standards.

*Unrealized Gains and Losses on Derivative Instruments*

The FERC accounting and reporting standards require that unrealized gains and losses on derivative instruments that are not probable of recovery in rates be classified gross in the statement of income 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 in the Statement 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.

*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 revenue; valuation of energy contracts; effects of regulation; AROs, 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.

*Cash Equivalents and Restricted Cash*

Cash equivalents consist of funds invested in money market accounts and in other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where availability is restricted by legal requirements, loan agreements or other contractual provisions. Restricted amounts are included in other special funds and special deposits in the Comparative Balance Sheet. Cash and cash equivalents are as follows (in millions):

| | Years Ended December 31, 2008 | 2007 |
|---|---|---|
| Cash (131) | $ 16 | $ 11 |
| Working funds (135) | - | - |
| Temporary cash investments (136) | 4 | 182 |
| Total cash and cash equivalents | $ 20 | $ 193 |

*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 ratemaking 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 ratemaking 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 no longer probable that these costs will be recovered, the regulatory assets and regulatory 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 or the outcome of any pending disputes. The change in the balance of the allowance for doubtful accounts, which is included in accumulated provision for uncollectible accounts is summarized as follows (in millions):

| | Years Ended December 31, 2008 | 2007 |
|---|---|---|
| Beginning balance | $ 7 | $ 12 |
| Charged to operation expenses, net | 14 | 9 |
| Write-offs, net | (12) | (14) |
| Ending balance | $ 9 | $ 7 |

*Derivatives*

PacifiCorp employs a number of different commodity derivative instruments, including forward contracts, options, swaps and other agreements, to manage its commodity price, for example natural gas and electricity volatility. Derivative instruments are recorded in the Comparative Balance Sheet as either assets or liabilities and are stated at fair value unless they are designated as normal purchases or normal sales and qualify for the exemption afforded by GAAP. Derivative balances reflect reductions permitted under master netting arrangements with counterparties and cash collateral paid or received under such agreements. For those derivative contracts that are probable of recovery in rates, the unrealized gains and losses are recorded as a net regulatory asset or liability pursuant to SFAS No. 71.

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 or normal sales pursuant to the exemption. Contracts that qualify and are designated as normal purchases or normal sales are not marked to market. Recognition of these contracts in operating revenues or operation expenses in the Statement of Income occurs when the contracts settle.

For contracts designated in hedge relationships ("hedge contracts"), PacifiCorp formally assesses, at inception and thereafter, whether the hedge contracts are highly effective in offsetting changes in cash flows or fair values of the hedged items. PacifiCorp formally documents hedging activity by transaction type and risk management strategy.

Changes in the fair value of a derivative designated and qualified 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 ("AOCI"), 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 AOCI will remain in AOCI 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 AOCI are immediately recognized in earnings.

*Inventories*

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

*Property, Plant and Equipment, Net*

*General*

Property, plant and equipment is recorded at historical cost. PacifiCorp capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs, which include allowance for funds used during construction ("AFUDC"). 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 or sells its regulated property, plant and equipment, it charges the original cost and any cost of removal and salvage to accumulated provision for depreciation.

PacifiCorp records AFUDC, which represents the estimated costs of debt and equity funds necessary to finance additions to property, plant and equipment. AFUDC 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.

The weighted-average aggregate rates used for AFUDC were 8.2% and 8.3% for the years ended December 31, 2008 and 2007, respectively.

*Asset Retirement Obligations*

The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and 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 ARO 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 ARO liability due to the passage of time. The difference between the ARO liability, the corresponding ARO 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 a legal ARO, 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 or over the assets' estimated useful lives. Periodic depreciation studies are performed to determine the appropriate group lives, salvage and group depreciation rates. These studies are reviewed and approved by PacifiCorp's various regulatory bodies.

*Revenue Recognition*

Revenue is recognized as electricity is delivered and includes amounts for services rendered. Revenue recognized includes unbilled, as well as billed, amounts. Unbilled revenues included in customer accounts receivable in the Comparative Balance Sheet were $211 million and $192 million as of December 31, 2008 and 2007, respectively. Rates charged are subject to federal and state regulation.

The determination of sales to individual customers is based on the reading of the customer's meter, which is performed on a systematic basis throughout the month. At the end of each month, amounts of energy provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. The estimate is reversed in the following month and actual revenue is recorded based on subsequent meter readings.

The monthly unbilled revenues of PacifiCorp are determined by the estimation of unbilled energy provided during the period, the assignment of unbilled energy provided to customer classes and the average rate per customer class. Factors that can impact the estimate of unbilled energy provided include, but are not limited to, seasonal weather patterns, customer usage patterns, historical trends, volumes, line losses, retail rate changes and composition of customer classes.

PacifiCorp records sales, franchise and excise taxes, which are collected directly from customers and remitted directly to the 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 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 of PacifiCorp Holdings, Inc., PacifiCorp's former parent company.

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 AOCI are charged or credited directly to AOCI. 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 $409 million and $423 million as of December 31, 2008 and 2007, respectively, 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 income taxes, 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 United States Internal Revenue Service has closed its examination of PacifiCorp's income tax returns through the 2000 tax year. In most cases, state jurisdictions have closed their examinations of PacifiCorp's income tax returns through 1993. 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 results. Assets and liabilities are established for uncertain tax positions taken or positions expected to be taken in income tax returns when such positions are judged to not meet the "more-likely-than-not" threshold based on the technical merits of the position. PacifiCorp's unrecognized tax benefits are primarily included in miscellaneous current and accrued assets, interest and dividends receivable and interest accrued in the Comparative Balance Sheet. PacifiCorp recognizes interest and penalties related to income taxes in interest income, interest expense and penalties in the Statement of Income.

*Segment Information*

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

*New Accounting Pronouncements*

In December 2008, the Financial Accounting Standards Board (the "FASB") issued FASB Staff Position ("FSP") No. 132(R)-1, *Employers' Disclosures about Postretirement Benefit Plan Assets* ("FSP FAS 132(R)-1"). FSP FAS 132(R)-1 is intended to improve financial reporting about plan assets of defined benefit pension and other postretirement plans by requiring enhanced disclosures to enable investors to better understand how investment allocation decisions are made and the major categories of plan assets. FSP FAS 132(R)-1 also requires disclosure of the inputs and valuation techniques used to measure fair value and the effect of fair value measurements using significant unobservable inputs on changes in plan assets. In addition, FSP FAS 132(R)-1 establishes disclosure requirements for significant concentrations of risk within plan assets. FSP FAS 132(R)-1 is effective for financial statements issued for fiscal years beginning after December 15, 2009, with early application permitted. PacifiCorp is currently evaluating the impact of adopting FSP FAS 132(R)-1 on its disclosures included within Notes to Financial Statements.

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 is intended to improve financial reporting about derivative instruments and hedging activities by requiring enhanced disclosures to enable investors to better understand how and why an entity uses derivative instruments and their effects on an entity's financial position, financial performance and cash flows. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008 with early application encouraged. PacifiCorp is currently evaluating the impact of adopting SFAS No. 161 on its disclosures included within Notes to Financial Statements.

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.

In September 2006, 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. Under SFAS No. 157, fair value refers to the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the principal or most advantageous market. The standard clarifies that fair value should be based on the assumptions market participants would use when pricing the asset or liability. In February 2008, the FASB issued FSP No. 157-2, *Effective Date of FASB Statement No. 157*, which delays the effective date of SFAS No. 157 for all non-financial assets and liabilities, except those that are recognized or disclosed at fair value in the consolidated financial statements on a recurring basis, until fiscal years beginning after November 15, 2008. These non-financial items include assets and liabilities such as non-financial assets and liabilities assumed in a business combination, reporting units measured at fair value in a goodwill impairment test and AROs initially measured at fair value. In October 2008, the FASB issued FSP No. 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active* ("FSP FAS 157-3"), which clarifies the application of SFAS No. 157 in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. FSP FAS 157-3 was effective upon issuance, including prior periods for which financial statements had not been issued. PacifiCorp adopted the provisions of SFAS No. 157 for assets and liabilities recognized at fair value on a recurring basis effective January 1, 2008. The partial adoption of SFAS No. 157 did not have a material impact on PacifiCorp's Financial Statements.

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 provisions of SFAS No. 158 at 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. PacifiCorp adopted the requirement to measure plan assets and benefit obligations as of the date of its fiscal year-end at December 31, 2008. Upon adoption of the measurement date provisions, PacifiCorp recorded a transitional adjustment of $14 million, $12 million of which is considered probable of recovery in rates and was recorded as a regulatory asset. The remaining $2 million (pre-tax) is not considered probable of recovery in rates and was recorded as a reduction in retained earnings.

## (3) Property, Plant and Equipment, Net

*Depreciable Lives*

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

| | |
|---|---|
| Generation: | |
| Steam plant | 20 – 57 years |
| Hydroelectric plant | 24 – 80 years |
| Wind plant | 25 years |
| Other plant | 15 – 40 years |
| Transmission | 25 – 75 years |
| Distribution | 44 – 52 years |
| Intangible plant (1) | 5 – 50 years |
| Other | 5 – 29 years |

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

*Utility Plant Acquisition*

On September 15, 2008, after having received the required regulatory approvals, PacifiCorp acquired from TNA Merchant Projects, Inc., an affiliate of Suez Energy North America, Inc., 100% of the equity interests of Chehalis Power Generating, LLC, an entity owning a 520-megawatt ("MW") natural gas-fired generating plant located in Chehalis, Washington. The total cash purchase price was $308 million and the estimated fair value of the acquired entity was primarily allocated to the plant. Chehalis Power Generating, LLC was merged into PacifiCorp immediately following the acquisition. The results of the plant's operations have been included in PacifiCorp's Financial Statements since the acquisition date.

*Unallocated Acquisition Adjustments*

PacifiCorp has unallocated acquisition adjustments that represent the excess of costs of the acquired interests in property, plant and equipment purchased from the entity that first devoted the assets to utility service over their net book value in those assets. These unallocated acquisition adjustments included in utility plant had an original cost of $157 million as of December 31, 2008 and 2007 and accumulated provision for depreciation, amortization and depletion of $91 million and $85 million as of December 31, 2008 and 2007, respectively.

*Depreciation Study*

In August 2007, PacifiCorp filed applications with the regulatory commissions in Utah, Oregon, Wyoming, Washington and Idaho to change its rates of depreciation prospectively based on a new depreciation study. PacifiCorp received approval to change the depreciation rates effective January 1, 2008. The Oregon Public Utility Commission (the "OPUC") order required additional modifications related to the depreciation lives of coal-fired generating facilities, which were approved in August 2008. The revised depreciation rates generally reflect an extension of the lives of PacifiCorp's assets. The most significant change resulted in an increase in the range of depreciable lives for steam plant from 20 –43 years to 20 – 57 years. The revised depreciation rates resulted in a benefit to pre-tax income during the year ended December 31, 2008 of approximately $47 million.

**(4) Jointly Owned Utility Facilities**

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

The amounts shown in the table below represent PacifiCorp's share in each jointly owned facility as of December 31, 2008 (dollars in millions):

| | PacifiCorp Share | Facility in Service | Accumulated Depreciation/ Amortization | Construction Work in Progress |
|---|---|---|---|---|
| Jim Bridger Nos. 1 – 4 (1) | 67% | $ 996 | $ 502 | $ 29 |
| Wyodak (1) | 80 | 333 | 177 | 4 |
| Hunter No. 1 | 94 | 305 | 153 | 8 |
| Colstrip Nos. 3 and 4 (1) | 10 | 244 | 127 | 2 |
| Hunter No. 2 | 60 | 194 | 92 | 10 |
| Hermiston (2) | 50 | 173 | 42 | - |
| Craig Nos. 1 and 2 | 19 | 168 | 81 | - |
| Hayden No. 1 | 25 | 45 | 22 | 1 |
| Foote Creek | 79 | 37 | 15 | - |
| Hayden No. 2 | 13 | 28 | 15 | 1 |
| Other transmission and distribution facilities | Various | 83 | 24 | - |
| Total | | $ 2,606 | $ 1,250 | $ 55 |

(1) Includes transmission lines and substations.

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

## (5) Regulatory Matters

*Regulatory Assets and Liabilities*

Regulatory assets represent costs that are expected to be recovered in future rates. Regulatory liabilities represent income to be recognized or amounts to be returned to customers in future periods. PacifiCorp had regulatory assets not earning a return on investment of $1.5 billion and $945 million as of December 31, 2008 and 2007, respectively.

*Rate Matters*

*Oregon*

In October 2007, PacifiCorp filed its tax report for 2006 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 a report annually with the OPUC comparing income taxes collected and income taxes paid, as defined by the statute and its administrative rules. PacifiCorp's filing indicated that for the 2006 tax year, PacifiCorp paid $33 million more in federal, state and local taxes than was collected in rates from its retail customers. PacifiCorp proposed to recover $27 million of the deficiency over a one-year period starting June 1, 2008 and to defer any excess into a balancing account for future disposition. During the review process, PacifiCorp updated its filing to address the OPUC's staff recommendations, which increased the initial request by $2 million for a total of $35 million. In April 2008, the OPUC approved PacifiCorp's revised request with $27 million to be recovered over a one-year period beginning June 1, 2008 and the remainder to be deferred until a later period, with interest to accrue at PacifiCorp's authorized rate of return. In June 2008, PacifiCorp recorded a $27 million regulatory asset and associated revenues representing the amount that PacifiCorp will collect from its Oregon retail customers over the one-year period that began on June 1, 2008.

In May 2008, the Industrial Customers of Northwest Utilities ("ICNU") filed a petition with the Court of Appeals of the State of Oregon seeking judicial review of the final order with regards to PacifiCorp's 2006 SB 408 tax report. In December 2008, ICNU filed their opening brief. In March 2009, a notice of withdrawal of the SB 408 order in judicial review was issued by OPUC. The notice states that the purpose is to reconsider the order in light of the contentions raised on appeal. In the notice, the OPUC proposes to affirm, modify, or reverse the order by May 25, 2009. The notice suspends the proceedings before the Court of Appeals until the OPUC issues an order or until the time for issuing an order expires on May 25, 2009. The order has not been stayed and remains in lawful effect. PacifiCorp believes the outcome of these proceedings will not have a material impact on its financial results.

In October 2008, PacifiCorp filed its tax report for 2007 under SB 408. PacifiCorp's filing indicated that for the 2007 tax year, PacifiCorp paid $4 million more in federal, state and local taxes than was collected in rates from its retail customers.

## (6) Fair Value Measurements

The carrying amounts of PacifiCorp's cash and cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximate fair value because of the short-term maturity of these instruments. PacifiCorp has various financial instruments that are measured at fair value in the Financial Statements, including commodity derivatives. PacifiCorp's financial assets and liabilities are measured using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 – Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that PacifiCorp has the ability to access at the measurement date.
- Level 2 – Inputs include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).
- Level 3 – Unobservable inputs reflect PacifiCorp's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. PacifiCorp develops these inputs based on the best information available, including PacifiCorp's own data.

The following table presents PacifiCorp's assets and liabilities recognized in the Comparative Balance Sheet and measured at fair value on a recurring basis as of December 31, 2008 (in millions):

| | Input Levels for Fair Value Measurements | | | | |
|---|---|---|---|---|---|
| Description | Level 1 | Level 2 | Level 3 | Other (1) | Total |
| **Assets:** | | | | | |
| Commodity derivatives | $ - | $ 474 | $ 88 | $ (302) | $ 260 |
| **Liabilities:** | | | | | |
| Commodity derivatives | $ - | $ (485) | $ (496) | $ 361 | $ (620) |

(1) Primarily represents netting under master netting arrangements and cash collateral requirements.

PacifiCorp uses various derivative instruments, including forward contracts, options, swaps and other agreements. The fair value of derivative instruments is determined using unadjusted quoted prices for identical instruments on the applicable exchange in which PacifiCorp transacts. When quoted prices for identical instruments are not available, PacifiCorp uses forward price curves derived from market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent energy brokers, exchanges, direct communication with market participants and actual transactions executed by PacifiCorp. Market price quotations for certain major electricity and natural gas 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. Market price quotations for other electricity and natural gas trading hubs are not as readily obtainable for the six years or if the instrument is not actively traded. Given that limited market data exists for these instruments, PacifiCorp uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on significant unobservable inputs.

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.

The following table reconciles the beginning and ending balance of PacifiCorp's assets and liabilities measured at fair value on a recurring basis using significant Level 3 inputs (in millions):

| | Commodity Derivatives |
|---|---|
| **Balance, January 1, 2008** | $ (311) |
| Unrealized gains (losses) included in regulatory assets | (103) |
| Purchases, sales, issuances and settlements | (7) |
| Net transfers into Level 3 | 13 |
| **Balance, December 31, 2008** | $ (408) |

PacifiCorp's long-term debt and current maturities of long-term debt are carried at cost in the Financial Statements. The fair value of PacifiCorp's long-term debt 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 fixed-rate and variable-rate long-term debt, including the current portion as of December 31 (in millions):

| | 2008 | | 2007 | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Long-term debt | $ 5,503 | $ 5,769 | $ 5,117 | $ 5,350 |

## (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 instruments, including forward contracts, options, swaps and other agreements. 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, 2008 and 2007, 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, 2008 (in millions):

| | Net Derivative Assets (Liabilities)(1) | | | Net Regulatory Assets (Liabilities) |
|---|---|---|---|---|
| | Assets | Liabilities | Total | |
| Commodity | $ 260 | $ (620) | $ (360) | $ 442 |
| Current | $ 174 | $ (130) | $ 44 | |
| Non-current | 86 | (490) | (404) | |
| Total | $ 260 | $ (620) | $ (360) | |

(1) Net derivative assets (liabilities) include $82 million of a net asset for cash collateral.

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

| | Net Derivative Assets (Liabilities) | | | Net Regulatory Assets (Liabilities) |
|---|---|---|---|---|
| | Assets | Liabilities | Total | |
| Commodity | $ 357 | $ (614) | $ (257) | $ 257 |
| Foreign currency | 1 | - | 1 | (1) |
| | $ 358 | $ (614) | $ (256) | $ 256 |
| Current | $ 143 | $ (117) | $ 26 | |
| Non-current | 215 | (497) | (282) | |
| Total | $ 358 | $ (614) | $ (256) | |

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, | |
|---|---|---|
| | 2008 | 2007 |
| Other income: | | |
| Miscellaneous nonoperating income (421) | $ (143) | $ (163) |
| Other income deductions: | | |
| Other deductions (426.5) | 143 | 161 |
| Total unrealized gain (loss) on derivative contracts | $ - | $ (2) |

Realized and 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 physically settled derivative contracts not held for trading purposes are presented in the Statement of Income as operating 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 operating 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 Collateral*

Amounts recognized for cash collateral received from others that was offset against net derivative assets totaled $78 million as of December 31, 2008 compared to $160 million of cash collateral provided to others that was offset against net derivative liabilities as of December 31, 2008. The amounts of cash collateral received or provided vary primarily based on changes in fair value of the related positions.

**(8) Short-Term Borrowings**

*Short-Term Debt*

As of December 31, 2008, PacifiCorp had outstanding short-term debt borrowings of $85 million consisting of commercial paper at an average interest rate of 1.0%. As of December 31, 2007, PacifiCorp had no outstanding short-term debt borrowings.

*Revolving Credit Agreements*

As of December 31, 2008, PacifiCorp had $1.5 billion of total bank commitments under two unsecured revolving credit facilities. However, PacifiCorp's effective liquidity under these facilities was reduced by $105 million to $1.4 billion due to the Lehman Brothers Holdings Inc. ("Lehman") bankruptcy filing in September 2008. Lehman filed for protection under Chapter 11 of the Federal Bankruptcy Code in the United States Bankruptcy Court in the Southern District of New York. Lehman Brothers Bank, FSB and Lehman Commercial Paper, Inc., both subsidiaries of Lehman, have commitments totaling $105 million in PacifiCorp's $1.5 billion unsecured revolving credit facilities. The reduction in available capacity under the credit facilities as a result of the Lehman bankruptcy did not have a material adverse impact on PacifiCorp.

Adjusting for the Lehman bankruptcy, the first credit facility has $760 million of total bank commitments through July 6, 2011. The commitments reduce over time to $630 million of remaining availability for the year ending July 6, 2013. Adjusting for the Lehman bankruptcy, the second credit facility has $635 million of total bank commitments through October 23, 2012. Each credit facility includes a variable interest rate borrowing option based on the London Interbank Offered Rate, plus a margin that is currently 0.155% and varies based on PacifiCorp's credit ratings for its senior unsecured long-term debt securities. These credit facilities support PacifiCorp's commercial paper program, unenhanced variable-rate tax-exempt bond obligations and other short-term borrowing needs.

As of December 31, 2008, PacifiCorp had no borrowings outstanding under either credit facility but had letters of credit under both credit agreements totaling $220 million to support variable-rate tax-exempt bond obligations. In addition, the credit facilities supported $85 million of commercial paper borrowings and $38 million of unenhanced variable-rate tax-exempt bond obligations outstanding as of December 31, 2008. The remaining $1.1 billion of effective liquidity under the unsecured revolving credit facilities was available as of December 31, 2008.

As of December 31, 2007, 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. As of December 31, 2008, PacifiCorp was in compliance with the covenants of its revolving credit and other financing agreements.

## (9) Long-Term Debt and Capital Lease Obligations

PacifiCorp's long-term debt and capital lease obligations were as follows as of December 31 (in millions):

| | 2008 | | | 2007 | |
|---|---|---|---|---|---|
| | Par Value | Amount | Average Interest Rate | Amount | Average Interest Rate |
| Long-term debt: | | | | | |
| First mortgage bonds: | | | | | |
| 4.3% to 9.2%, due through 2013 | $ 977 | $ 976 | 6.9% | $ 1,389 | 6.5% |
| 5.0% to 8.7%, due 2014 to 2018 | 721 | 720 | 5.5 | 221 | 5.3 |
| 6.7% to 8.5%, due 2021 to 2023 | 324 | 324 | 7.7 | 324 | 7.7 |
| 6.7% due 2026 | 100 | 100 | 6.7 | 100 | 6.7 |
| 7.7% due 2031 | 300 | 299 | 7.7 | 299 | 7.7 |
| 5.3% to 6.4%, due 2034 to 2038 | 2,350 | 2,345 | 6.0 | 2,046 | 5.9 |
| Tax-exempt bond obligations: | | | | | |
| Variable rates, due 2013(1)(2) | 41 | 41 | 0.8 | 41 | 3.8 |
| Variable rates, due 2014 to 2025(2) | 325 | 325 | 1.1 | 325 | 3.5 |
| Variable rates, due 2024(1)(2) | 176 | 176 | 0.9 | 176 | 3.8 |
| 3.4% to 5.7%, due 2014 to 2025(1) | 184 | 184 | 4.5 | 183 | 4.5 |
| 6.2% due 2030 | 13 | 13 | 6.2 | 13 | 6.2 |
| Total long-term debt | $ 5,511 | $ 5,503 | | $ 5,117 | |
| Capital lease obligations: | | | | | |
| 8.8% to 14.8%, due through 2036 | 65 | 65 | 11.6 | 49 | 11.3 |
| Less current maturities | (6) | (6) | | (1) | |
| Non current capital lease obligations | $ 59 | $ 59 | | $ 48 | |

(1) Secured by pledged first mortgage bonds generally at the same interest rates, maturity dates and redemption provisions as the tax-exempt bond obligations.

(2) 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 $17.8 billion of the eligible assets (based on original cost) of PacifiCorp were subject to the lien of the mortgage as of December 31, 2008.

In January 2009, PacifiCorp issued $350 million of its 5.50% First Mortgage Bonds due January 15, 2019 and $650 million of its 6.00% First Mortgage Bonds due January 15, 2039.

In September 2008, PacifiCorp acquired $216 million of its insured variable-rate tax-exempt bond obligations due to the significant reduction in market liquidity for insured variable-rate obligations. In November 2008, the associated insurance and related standby bond purchase agreements were terminated and these variable-rate long-term debt obligations were remarketed with credit enhancement and liquidity support provided by $220 million of letters of credit issued under PacifiCorp's two unsecured revolving credit facilities.

In January 2008, PacifiCorp received regulatory authority from the OPUC and the Idaho Public Utilities Commission to issue up to an additional $2.0 billion of long-term debt. PacifiCorp must make a notice filing with the Washington Utilities and Transportation Commission prior to any future issuance. Also in January 2008, PacifiCorp filed a shelf registration statement with the United States Securities and Exchange Commission covering future first mortgage bond issuances. PacifiCorp's long-term debt issuances in January 2009 and during the year ended December 31, 2008 were covered under the above-noted regulatory authorities and shelf registration statement.

As of December 31, 2008, $4.3 billion of first mortgage bonds were redeemable at PacifiCorp's option at redemption prices dependent upon United States Treasury yields. As of December 31, 2008, $542 million of variable-rate tax-exempt bond obligations and $84 million of fixed-rate tax-exempt bond obligations were redeemable at PacifiCorp's option at par. The remaining long-term debt was not redeemable as of December 31, 2008.

As of December 31, 2008, PacifiCorp had $517 million of letters of credit available to provide credit enhancement and liquidity support for variable-rate tax-exempt bond obligations totaling $504 million plus interest. These committed bank arrangements were fully available at December 31, 2008 and expire periodically through May 2012.

In addition, as of December 31, 2008, PacifiCorp had approximately $18 million of letters of credit available to provide credit support for certain transactions as requested by third parties. These committed bank arrangements were all fully available as of December 31, 2008 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 letters of credit 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 as of December 31, 2008, 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, purchase power agreements, real estate and for the use of certain equipment that qualify as capital leases. The transportation services agreements included as capital leases are for the right to use pipeline facilities to provide natural gas to three of PacifiCorp's generating facilities. Net assets accounted for as capital leases of $65 million and $49 million as of December 31, 2008 and 2007, respectively, were included in net utility plant in the Comparative Balance Sheet.

The annual maturities of long-term debt and capital lease obligations for the years beginning January 1, 2009 and thereafter, excluding unamortized discounts, are as follows (in millions):

| | Long-term Debt | Capital Lease Obligations (1) | Total |
|---|---|---|---|
| 2009 | $ 139 | $ 13 | $ 152 |
| 2010 | 14 | 9 | 23 |
| 2011 | 587 | 8 | 595 |
| 2012 | 17 | 8 | 25 |
| 2013 | 261 | 12 | 273 |
| Thereafter | 4,493 | 106 | 4,599 |
| Total | 5,511 | 156 | 5,667 |
| Amounts representing interest (2) | - | (91) | (91) |
| Total | $ 5,511 | $ 65 | $ 5,576 |

(1) Excluded from these amounts are approximately $46 million of capital lease executory costs, including taxes, maintenance and insurance.

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

## (10) Asset Retirement Obligations

PacifiCorp estimates its ARO 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. Changes in estimates could occur for a number of reasons, including plan revisions, inflation and changes in the amount and timing of the expected work.

PacifiCorp does not recognize liabilities for AROs 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, distribution and other assets cannot currently be estimated and no amounts are recognized in the Financial Statements other than those included in the regulatory removal cost liability established via approved depreciation rates.

The change in the balance of the total ARO liability is summarized as follows as of December 31 (in millions):

| | 2008 | 2007 |
|---|---|---|
| Balance, January 1 | $ 75 | $ 86 |
| Additions | 2 | 1 |
| Retirements | (4) | (6) |
| Change in estimated costs (1) | 4 | (11) |
| Accretion (2) | 4 | 5 |
| Balance, December 31 | $ 81 | $ 75 |

(1) Results from changes in the timing and amounts of estimated cash flows for certain plant and mine reclamation.

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

Certain of PacifiCorp's decommissioning and reclamation obligations relate to jointly owned facilities and mine sites. For decommissioning, PacifiCorp is committed to pay a proportionate share of the decommissioning costs based upon its ownership percentage, or in the case of mine reclamation obligations, PacifiCorp has committed to pay a proportionate share of mine 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's estimated share of the decommissioning and reclamation obligations are primarily recorded as ARO liabilities.

**(11) 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 a defined contribution 401(k) employee savings plan (the "401(k) Plan"). Non-union employees hired on or after January 1, 2008 and certain union new hires are not eligible to participate in the PacifiCorp Retirement Plan (the "Retirement Plan"). These employees are eligible to receive enhanced benefits under the 401(k) Plan.

**Pension and Other Postretirement Benefit Plans**

PacifiCorp's pension plans include a non-contributory defined benefit pension plan, the Retirement Plan; the Supplemental Executive Retirement Plan (the "SERP"); and certain joint trust union plans to which PacifiCorp contributes on behalf of certain bargaining units. Benefits for certain 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. At December 31, 2008, all non-union Retirement Plan participants, as well as certain union participants, earn benefits based on a cash balance formula. Refer to the discussion of curtailments below.

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.

*Measurement Date Change*

PacifiCorp adopted the measurement date provisions of SFAS No. 158 at December 31, 2008, which requires that an employer measure plan assets and benefit obligations at the end of the employer's fiscal year. Effective December 31, 2008, PacifiCorp changed its measurement date from September 30 to December 31 and recorded a $14 million transitional adjustment. The components of the measurement date change transitional adjustment were as follows on a pre-tax basis (in millions):

| | Pension | Other Postretirement | Total |
|---|---|---|---|
| Service cost | $ 7 | $ 2 | $ 9 |
| Interest cost | 16 | 8 | 24 |
| Expected return on plan assets | (18) | (7) | (25) |
| Net amortization | 2 | 4 | 6 |
| Total | $ 7 | $ 7 | $ 14 |

The $14 million transitional adjustment includes $12 million recorded as an increase in regulatory assets for the portion considered probable of recovery in rates and $2 million recorded as a reduction ($1 million after-tax) in retained earnings for the portion not considered probable of recovery in rates. The $12 million increase to regulatory assets will be amortized over three to 10 years based on agreements with various state regulatory commissions. The recognition of service cost, interest cost and expected return on plan assets, totaling $8 million, resulted in an increase in pension and other postretirement liabilities. The $6 million net amortization represents recognition of prior service cost, net transition obligation and actuarial net loss and resulted in a reduction in regulatory assets.

*Curtailments*

In August 2008, non-union employee participants in the Retirement Plan were offered the option to continue to receive pay credits in their current cash balance formula of the Retirement Plan or receive equivalent fixed contributions to the 401(k) Plan. The election was effective January 1, 2009, and resulted in the recognition of a $38 million curtailment gain. PacifiCorp recorded $36 million of the curtailment gain as a reduction to regulatory assets as of December 31, 2008, representing the amount to be returned to customers in rates. The reduction to the regulatory asset will be amortized over a period of three to 10 years based on agreements with various state regulatory commissions.

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 the 401(k) Plan with enhanced benefits. As a result of this election, the Local 659 participants' Retirement Plan benefits were frozen as of December 31, 2007. This change resulted in a $2 million curtailment gain that was recorded as a reduction to regulatory assets as of December 31, 2008 based on the requirement to return the amount to customers in rates. It will be amortized over a period of three to 10 years based on agreements with various state regulatory commissions. Also as a result of this change, PacifiCorp's pension liability and regulatory assets each decreased by $13 million.

*Change in Benefit Formula*

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.

*Net Periodic Benefit Cost*

For purposes of calculating the expected return on plan assets, a market-related value is used. 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. In addition, as differences between expected and actual investment returns are admitted into the market-related value of plan assets, the corresponding gains or losses are then amortized and included in the net amortization component of net periodic benefit cost.

Net periodic benefit cost for the pension and other postretirement benefit plans included the following components (in millions):

| | Pension | | Other Postretirement | |
|---|---|---|---|---|
| | Years Ended December 31, | | Years Ended December 31, | |
| | 2008 (2) | 2007 | 2008 (2) | 2007 |
| Service cost (1) | $ 27 | $ 29 | $ 7 | $ 7 |
| Interest cost | 67 | 71 | 33 | 33 |
| Expected return on plan assets | (72) | (68) | (28) | (26) |
| Net amortization | 7 | 23 | 15 | 19 |
| Cost of termination benefits | - | 1 | - | - |
| Curtailment loss (gain) | (2) | - | - | - |
| Net periodic benefit cost | $ 27 | $ 56 | $ 27 | $ 33 |

(1) Service cost excludes $11 million and $10 million of contributions to the joint trust union plans during the years ended December 31, 2008 and 2007, respectively.

(2) Excludes impact of the measurement date change and the portion of the curtailment gains required to be returned to customers in rates. Refer to "Measurement Date Change" and "Curtailments" above.

*Funded Status*

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

| | Pension | | Other Postretirement | |
|---|---|---|---|---|
| | Years Ended December 31, | | Years Ended December 31, | |
| | 2008 | 2007 | 2008 | 2007 |
| Plan assets at fair value, beginning of year | $ 963 | $ 884 | $ 378 | $ 318 |
| Employer contributions | 70 | 80 | 42 | 46 |
| Participant contributions | - | - | 14 | 11 |
| Actual return on plan assets | (224) | 118 | (103) | 46 |
| Benefits paid | (117) | (119) | (47) | (43) |
| Plan assets at fair value, end of year | $ 692 | $ 963 | $ 284 | $ 378 |

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

| | Pension | | Other Postretirement | |
|---|---|---|---|---|
| | Years Ended December 31, | | Years Ended December 31, | |
| | 2008 | 2007 | 2008 | 2007 |
| Benefit obligation, beginning of year | $ 1,111 | $ 1,333 | $ 536 | $ 566 |
| Service cost (1) | 34 | 29 | 9 | 7 |
| Interest cost (1) | 83 | 71 | 41 | 33 |
| Participant contributions | - | - | 14 | 11 |
| Plan amendments | (7) | (130) | (12) | - |
| Curtailment | (13) | - | - | - |
| Actuarial gain | (21) | (74) | (56) | (40) |
| Benefits paid, net of Medicare subsidy | (117) | (119) | (43) | (41) |
| Cost of termination benefits | - | 1 | - | - |
| Benefit obligation, end of year | $ 1,070 | $ 1,111 | $ 489 | $ 536 |
| | | | | |
| Accumulated benefit obligation, end of year | $ 1,048 | $ 1,061 | | |

(1) Included in the pension and other postretirement liabilities increase in connection with the measurement date change in 2008 was additional service cost of $7 million and $2 million and additional interest cost of $16 million and $8 million for the pension and other postretirement benefit plans, respectively.

The funded status of the plans and the amounts recognized in the Comparative Balance Sheet are as follows as of December 31 (in millions):

| | Pension | | Other Postretirement | |
|---|---|---|---|---|
| | 2008 | 2007 | 2008 | 2007 |
| Plan assets at fair value, end of year | $ 692 | $ 963 | $ 284 | $ 378 |
| Less – Benefit obligation, end of year | 1,070 | 1,111 | 489 | 536 |
| Funded status | (378) | (148) | (205) | (158) |
| Contributions after the measurement date but before year-end | - | - | - | 12 |
| Amounts recognized in the Comparative Balance Sheet | $ (378) | $ (148) | $ (205) | $ (146) |
| Amounts recognized in the Comparative Balance Sheet: | | | | |
| Other current liabilities | $ (4) | $ (4) | $ - | $ - |
| Other long-term liabilities | (374) | (144) | (205) | (146) |
| Amounts recognized | $ (378) | $ (148) | $ (205) | $ (146) |

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 $38 million and $40 million as of December 31, 2008 and 2007, respectively. These assets are not included in the plan assets in the above table, but are reflected in the Comparative Balance Sheet. The portion of the pension plans' projected benefit obligation related to the SERP was $50 million and $52 million as of December 31, 2008 and 2007, respectively. The SERP's accumulated benefit obligation totaled $50 million and $52 million as of December 31, 2008 and 2007, respectively.

*Unrecognized Amounts*

The portion of the funded status of the plans not yet recognized in net periodic benefit cost is as follows as of December 31 (in millions):

| | Pension | | Other Postretirement | |
|---|---|---|---|---|
| | 2008 | 2007 | 2008 | 2007 |
| Amounts not yet recognized as components of net periodic benefit cost: | | | | |
| Net loss | $ 508 | $ 250 | $ 128 | $ 45 |
| Prior service cost (credit) | (68) | (115) | 1 | 17 |
| Net transition obligation | - | 3 | 45 | 60 |
| Regulatory deferrals (1) | (32) | - | 6 | - |
| Total | $ 408 | $ 138 | $ 180 | $ 122 |

(1) Consists of amounts related to the portion of the curtailment gains and the measurement date change transitional adjustment that are considered probable of inclusion in rates.

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2008 and 2007 is as follows (in millions):

| | Regulatory Asset | Accumulated Other Comprehensive Loss, Net | Total |
|---|---|---|---|
| Pension | | | |
| Balance, January 1, 2007 | $ 405 | $ 9 | $ 414 |
| Net gain arising during the year | (121) | (2) | (123) |
| Prior service credit arising during the year | (129) | (1) | (130) |
| Net amortization | (23) | - | (23) |
| Total | (273) | (3) | (276) |
| Balance, December 31, 2007 | $ 132 | $ 6 | $ 138 |
| | | | |
| Balance, January 1, 2008 | $ 132 | $ 6 | $ 138 |
| Net (gain) loss arising during the year | 293 | (2) | 291 |
| Prior service credit arising during the year | (7) | - | (7) |
| Curtailment gains | (11) | - | (11) |
| Measurement date change | 6 | - | 6 |
| Net amortization (1) | (9) | - | (9) |
| Total | 272 | (2) | 270 |
| Balance, December 31, 2008 | $ 404 | $ 4 | $ 408 |

| | Regulatory Asset | Deferred Income Taxes | Total |
|---|---|---|---|
| Other Postretirement | | | |
| Balance, January 1, 2007 | $ 161 | $ 40 | $ 201 |
| Net gain arising during the year | (47) | (13) | (60) |
| Net amortization | (19) | - | (19) |
| Total | (66) | (13) | (79) |
| Balance, December 31, 2007 | $ 95 | $ 27 | $ 122 |
| | | | |
| Balance, January 1, 2008 | $ 95 | $ 27 | $ 122 |
| Net loss (gain) arising during the year | 91 | (7) | 84 |
| Prior service credit arising during the year | (13) | - | (13) |
| Measurement date change | 6 | - | 6 |
| Net amortization (1) | (19) | - | (19) |
| Total | 65 | (7) | 58 |
| Balance, December 31, 2008 | $ 160 | $ 20 | $ 180 |

(1) Included in the regulatory asset decrease in connection with the measurement date change in 2008 was additional amortization of $2 million and $4 million for the pension and other postretirement benefit plans, respectively.

The net loss, prior service credit, net transition obligation and regulatory deferrals that will be amortized in 2009 into net periodic benefit cost are estimated to be as follows (in millions):

| | Net Loss | Prior Service Credit | Net Transition Obligation | Regulatory Deferrals | Total |
|---|---|---|---|---|---|
| Pension benefits | $ 18 | $ (8) | $ - | $ (8) | $ 2 |
| Other postretirement benefits | - | - | 12 | 1 | 13 |
| Total | $ 18 | $ (8) | $ 12 | $ (7) | $ 15 |

*Plan Assumptions*

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

| | Pension Years Ended December 31, | | Other Postretirement Years Ended December 31, | |
|---|---|---|---|---|
| | 2008 | 2007 | 2008 | 2007 |
| Benefit obligations as of the measurement date: | | | | |
| Discount rate | 6.90% | 6.30% | 6.90% | 6.45% |
| Rate of compensation increase | 3.50 | 4.00 | N/A | N/A |
| Net benefit cost for the period ended: | | | | |
| Discount rate | 6.30% | 5.76% | 6.45% | 6.00% |
| Expected return on plan assets | 7.75 | 8.00 | 7.75 | 8.00 |
| Rate of compensation increase | 4.00 | 4.00 | N/A | N/A |

In establishing its assumption as to the expected return on plan assets, PacifiCorp reviews the expected asset allocation and develops return assumptions for each asset class based on historical performance and forward-looking views of the financial markets.

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

| | 2008 | 2007 |
|---|---|---|
| Health care cost trend rate assumed for next year — under 65 | 8% | 9% |
| Health care cost trend rate assumed for next year — over 65 | 6 | 7 |
| 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 |

A one-percentage-point change in assumed health care cost trend rates would have the following effects (in millions):

| | Increase (Decrease) One Percentage-Point Increase | Increase (Decrease) One Percentage-Point Decrease |
|---|---|---|
| Effect on total service and interest cost | $ 3 | $ (2) |
| Effect on other postretirement benefit obligation | 31 | (26) |

*Contributions and Benefit Payments*

Employer contributions to the pension, other postretirement benefit plans and the joint trust union plans are expected to be \$54 million, \$25 million and \$11 million, respectively, for 2009. Funding to the established pension trust is based upon the actuarially determined costs of the plan and the requirement of the Internal Revenue Code, the Employee Retirement Income Security Act of 1974 and the Pension Protection Act of 2006, as amended. PacifiCorp's policy is to contribute to its other postretirement benefit plan an amount equal to the sum of the net periodic cost and the expected Medicare subsidy.

The Plan's expected benefit payments to participants for its pension and other postretirement benefit plans for 2009 through 2013 and for the five years thereafter are summarized below (in millions):

| | Projected Benefit Payments | | | |
|---|---|---|---|---|
| | | Other Postretirement | | |
| | Pension | Gross | Medicare Subsidy | Net of Subsidy |
| 2009 | \$ 90 | \$ 36 | \$ (3) | \$ 33 |
| 2010 | 93 | 37 | (3) | 34 |
| 2011 | 95 | 38 | (4) | 34 |
| 2012 | 96 | 39 | (4) | 35 |
| 2013 | 101 | 40 | (5) | 35 |
| 2014 – 2018 | 504 | 220 | (30) | 190 |

*Investment Policy and Asset Allocation*

PacifiCorp's investment policy for its pension and other postretirement benefit plans is to balance risk and return through a diversified portfolio of equity securities, fixed income securities and other alternative investments. Asset allocation for the pension and other postretirement benefit plans are as indicated in the tables below. Maturities for fixed income securities are managed to targets consistent with prudent risk tolerances. Sufficient liquidity is maintained to meet near-term benefit payment obligations. The plans retain outside investment advisors to manage plan investments within the parameters outlined by PacifiCorp's Pension Investment Committee. The weighted-average return on assets assumption is based on historical performance for the types of assets in which the plans invest.

PacifiCorp's pension plan trust includes a separate account that is used to fund benefits for the other postretirement benefit plan. In addition to this separate account, the assets for other postretirement benefits are held in two Voluntary Employees' Beneficiaries Association ("VEBA") Trusts, each of which has its own investment allocation strategies. PacifiCorp's asset allocation (percentage of plan assets) as of December 31 was as follows:

| | Pension Plan Trust | | | VEBA Trusts | | |
|---|---|---|---|---|---|---|
| | 2008 | 2007 | Target | 2008 | 2007 | Target |
| Equity securities | 49% | 56% | 53 – 57% | 64% | 64% | 63 – 67% |
| Debt securities | 40 | 35 | 33 – 37 | 36 | 36 | 33 – 37 |
| Other | 11 | 9 | 8 – 12 | - | - | - |
| | 100% | 100% | | 100% | 100% | |

PacifiCorp's benefit plan asset allocations were impacted by the highly volatile capital markets in the second half of 2008.

*Defined Contribution Plan*

PacifiCorp's 401(k) Plan covers substantially all employees. PacifiCorp's contributions are based primarily on each participant's level of contribution and cannot exceed the maximum allowable for tax purposes to the 401(k) Plan. PacifiCorp's contributions were $23 million and $19 million during the years ended December 31, 2008 and 2007, respectively.

*Severance*

PacifiCorp incurred $- million in severance expense during the year ended December 31, 2008 and $4 million during the year ended December 31, 2007.

**(12) Income Taxes**

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

| | Years Ended December 31, 2008 | Years Ended December 31, 2007 |
|---|---|---|
| **Current:** | | |
| Federal | $ (64) | $ 145 |
| State | (6) | 18 |
| Total | (70) | 163 |
| **Deferred:** | | |
| Federal | 276 | 51 |
| State | 36 | 7 |
| Total | 312 | 58 |
| **Investment tax credits** | (4) | (8) |
| Total income tax expense | $ 238 | $ 213 |

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

| | Years Ended December 31, 2008 | 2007 |
|---|---|---|
| Federal statutory tax rate | 35% | 35% |
| State taxes, net of federal benefit | 3 | 3 |
| Effect of regulatory treatment of depreciation differences | 1 | 2 |
| Tax reserves | - | (2) |
| Tax credits (1) | (5) | (3) |
| Other | - | (3) |
| Effective income tax rate | 34% | 32% |

(1) Primarily attributable to the impact of federal renewable electricity production tax credits related to qualifying wind-powered generating facilities that extend 10 years from the date the facilities were placed in service.

The net deferred tax liability consists of the following as of December 31 (in millions):

| | 2008 | 2007 |
|---|---|---|
| **Deferred tax assets:** | | |
| Employee benefits | $ 246 | $ 139 |
| Derivative contracts | 169 | 107 |
| Regulatory liabilities | 42 | 44 |
| Other | 130 | 142 |
| | 587 | 432 |
| **Deferred tax liabilities:** | | |
| Property, plant and equipment | (1,656) | (1,374) |
| Regulatory assets | (880) | (688) |
| Other | (50) | (65) |
| | (2,586) | (2,127) |
| Net deferred tax liability | $ (1,999) | $ (1,695) |

The sale of PacifiCorp to MEHC on March 21, 2006 triggered certain tax related events that remain unsettled. PacifiCorp does not believe that the tax, if any, arising from the ultimate settlement of these events will have a material impact on its financial results.

PacifiCorp adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes–an interpretation of FASB Statement No.* 109, 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.

As of December 31, 2008 and 2007, PacifiCorp had a net asset of $13 million for uncertain tax positions. As of December 31, 2008 and 2007, the net asset for uncertain tax positions included $14 million and $15 million, respectively, of tax positions that, if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate to positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax benefits, other than applicable interest and penalties, would not affect PacifiCorp's effective tax rate. The uncertain tax positions were included in miscellaneous current and accrued assets in the Comparative Balance Sheet.

## (13) Commitments and 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 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. In March 2008, the court indefinitely postponed the date for the liability-phase trial. The remedy-phase trial has not yet been scheduled. The court also has before it a number of motions on which it has not yet ruled. 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.

*Environmental Regulation*

*Environmental Matters*

PacifiCorp is subject to federal, state and local laws and regulations regarding air and water quality, hazardous and solid waste disposal and other environmental matters that have the potential to impact PacifiCorp's current and future operations. PacifiCorp believes it is in material compliance with current environmental requirements.

*New Source Review*

As part of an industry-wide investigation to assess compliance with the New Source Review ("NSR") and Prevention of Significant Deterioration ("PSD") provisions, the United States Environmental Protection Agency (the "EPA") has requested from numerous utilities information and supporting documentation regarding their capital projects for various generating facilities. Between 2001 and 2003, PacifiCorp responded to requests for information relating to its capital projects at its generating facilities and has been engaged in periodic discussions with the EPA over several years regarding PacifiCorp's historical projects and their compliance with NSR and PSD provisions. 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 generating facility, when combined with a modification (i.e., a physical or operational change), may trigger NSR permitting. PacifiCorp cannot predict the outcome of its discussions with the EPA at this time; however, PacifiCorp could be required to install additional emissions controls, and incur additional costs and penalties, in the event it is determined that PacifiCorp's historical projects did not meet all regulatory requirements.

*Accrued Environmental Costs*

PacifiCorp is fully or partly responsible for environmental remediation at various contaminated sites, including sites that are or were part of PacifiCorp's operations and sites owned by third parties. PacifiCorp accrues environmental remediation expenses when the expenses are believed to be probable and can be reasonably estimated. The quantification of environmental exposures is based on many factors, including changing laws and regulations, advancements in environmental technologies, the quality of available site-specific information, site investigation results, expected remediation or settlement timelines, PacifiCorp's proportionate responsibility, contractual indemnities and 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 as of December 31, 2008 and 2007 was \$11 million and \$13 million, respectively, and is included in other deferred credits in the Comparative Balance Sheet. Environmental remediation liabilities that separately result from the normal operation of long-lived assets and that are associated with the retirement of those assets are separately accounted for as AROs. The December 31, 2008 recorded liability included \$2 million of discounted liabilities. Had none of the liabilities included in the \$11 million balance recorded as of December 31, 2008 been discounted, the total would have been \$11 million.

*Hydroelectric Relicensing*

PacifiCorp's hydroelectric portfolio consists of 47 generating facilities with an aggregate facility net owned capacity of 1,158 MW. The FERC regulates 98% of the net capacity of this portfolio through 16 individual licenses, which typically have terms of 30 to 50 years. In April 2008 and June 2008, the FERC issued new licenses for the Prospect and the Lewis River hydroelectric systems, respectively, as described below. PacifiCorp's Klamath hydroelectric system is the remaining hydroelectric generating facility actively engaged in the relicensing process 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 will be significant and will consist primarily of additional relicensing costs, as well as ongoing operations and maintenance expense and capital expenditures required by its hydroelectric licenses. Electricity generation reductions may result from the additional environmental requirements. PacifiCorp had incurred \$57 million and \$89 million in costs, included in construction work in progress, as of December 31, 2008 and 2007, respectively, for ongoing hydroelectric relicensing. Refer to Hydroelectric Commitments section below for a discussion regarding existing capital expenditures commitments related to hydroelectric licenses under which PacifiCorp is currently operating.

*Klamath Hydroelectric System – 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 Klamath hydroelectric system 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 operating under annual licenses until the relicensing process is complete. As part of the relicensing process, the FERC is required to perform an environmental review and 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 Klamath hydroelectric system's impact on endangered species under a new FERC license consistent with the FERC staff's recommended license alternative and terms and conditions issued by the United States Departments of the Interior and Commerce. These terms and conditions include construction of upstream and downstream fish passage facilities at the Klamath hydroelectric system's four mainstem dams. PacifiCorp will need to obtain water quality certifications from Oregon and California prior to the FERC issuing a final license. PacifiCorp currently has water quality applications pending in Oregon and California.

In November 2008, PacifiCorp signed a non-binding agreement in principle (the "AIP") that lays out a framework for the disposition of PacifiCorp's Klamath hydroelectric system relicensing process, including a path toward dam transfer and removal by an entity other than PacifiCorp no earlier than 2020. Parties to the AIP are PacifiCorp, the United States Department of the Interior, the State of Oregon and the State of California. Any transfer of facilities and subsequent removal are contingent on PacifiCorp reaching a comprehensive final settlement agreement with the AIP signatories and other stakeholders. Negotiations on a final agreement have begun and the AIP states that a final agreement is expected no later than June 30, 2009. As provided in the AIP, PacifiCorp's support for a definitive settlement will depend on the inclusion of protection for PacifiCorp and its customers from dam removal costs and liabilities.

The AIP includes provisions to:

- Perform studies and implement certain measures designed to benefit aquatic species and their habitat in the Klamath Basin;
- Support and implement legislation in Oregon authorizing a customer surcharge intended to cover potential dam removal; and
- Require parties to support proposed federal legislation introduced to facilitate a final agreement.

Assuming a final agreement is reached, the United States government will conduct scientific and engineering studies and consult with state, local and tribal governments and other stakeholders, as appropriate, to determine by March 31, 2012 whether the benefits of dam removal will justify the costs.

In addition to signing the AIP, PacifiCorp recently provided both the United States Fish and Wildlife Service and the National Marine Fisheries Service an interim conservation plan aimed at providing additional protections for endangered species in the Klamath Basin. PacifiCorp is currently collaborating with both agencies to implement the plan.

As of December 31, 2008 and 2007, PacifiCorp had $57 million and $48 million, respectively, in costs related to the relicensing of the Klamath hydroelectric system included in construction work in progress in the Comparative Balance Sheet.

*Lewis River Hydroelectric System – Lewis River, Washington*

PacifiCorp filed new license applications with the FERC for the 136-MW Merwin and 240-MW Swift No. 1 hydroelectric facilities in April 2004. An application for a new license for the 134-MW Yale hydroelectric facility 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 26 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 facilities. 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. In June 2008, the FERC issued new individual licenses for the Merwin, Swift No. 1 and Yale hydroelectric facilities, each for a period of 50 years, effective June 1, 2008. In July 2008, PacifiCorp filed a motion of request for clarification or rehearing on certain items, which were subsequently addressed by the FERC in its October 2008 order on rehearing. In October 2008, subsequent to the FERC's final order, $36 million in costs to relicense these facilities were transferred from construction work in progress to utility plant.

*Prospect Hydroelectric System – Rogue River, Oregon*

In June 2003, PacifiCorp submitted a final license application to the FERC for the Prospect Nos. 1, 2 and 4 hydroelectric facilities, with total nameplate ratings of 37 MW. In 2008, the FERC issued a new license for a period of 30 years effective April 1, 2008. Subsequent to the issuance of the new license, $7 million of costs incurred to relicense the Prospect hydroelectric system were transferred from construction work in progress to utility plant.

*Hydroelectric Commitments*

Some of PacifiCorp's hydroelectric licenses contain requirements for PacifiCorp to make certain capital expenditures related to its hydroelectric facilities. PacifiCorp estimates it is obligated to make capital expenditures of approximately $278 million over the next 10 years related to these licenses.

*FERC Issues*

*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, excluding PacifiCorp, 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 concluded 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.

*Purchase Obligations*

PacifiCorp has the following unconditional purchase obligations as of December 31, 2008 (in millions) that are not reflected in the Comparative Balance Sheet:

| | Payments Due During the Years Ending December 31, | | | | | | |
|---|---|---|---|---|---|---|---|
| | **2009** | **2010** | **2011** | **2012** | **2013** | **Thereafter** | **Total** |
| Purchased electricity | $ 419 | $ 389 | $ 254 | $ 176 | $ 171 | $ 1,628 | $ 3,037 |
| Fuel | 519 | 436 | 259 | 141 | 144 | 1,106 | 2,605 |
| Construction | 923 | 392 | 97 | 42 | 7 | 2 | 1,463 |
| Transmission | 80 | 76 | 70 | 63 | 59 | 545 | 893 |
| Operating leases | 5 | 4 | 4 | 4 | 3 | 36 | 56 |
| Other | 43 | 25 | 19 | 15 | 14 | 126 | 242 |
| Total commitments | $ 1,989 | $ 1,322 | $ 703 | $ 441 | $ 398 | $ 3,443 | $ 8,296 |

*Purchased Electricity*

As part of its energy resource portfolio, PacifiCorp acquires a portion of its electricity through long-term purchases and exchange agreements. PacifiCorp has several power purchase agreements with wind-powered and other generating facilities that are not included in the table above as the payments are based on the amount of energy generated and there are no minimum payments. Purchased electricity, including purchases under those contracts that are not included in the above table and purchases of short-term electricity, were $759 million and $793 million for the years ended December 31, 2008 and 2007, respectively. These amounts are net of the effects of bookouts and trading activities.

Included in the minimum fixed annual payments for purchased electricity above are commitments to purchase electricity from several hydroelectric systems under long-term arrangements with public utility districts. These purchases are made on a "cost-of-service" basis for a stated percentage of system output and for a like percentage of system 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. These arrangements accounted for less than 5% of PacifiCorp's 2008 and 2007 energy sources.

*Fuel*

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

*Construction*

PacifiCorp has an ongoing construction program to meet increased electricity usage, customer growth and system reliability objectives. As of December 31, 2008, PacifiCorp had estimated long-term purchase obligations related to its construction program primarily for new wind-powered generating facilities and for certain segments of the Energy Gateway Transmission Expansion Project. Amounts included in the purchase obligations table above relate to firm commitments. The following discussion describes overall commitments related to those entered into as a result of MEHC's March 2006 acquisition of PacifiCorp, as well as the Energy Gateway Transmission Expansion Project. The amounts described below include amounts to which PacifiCorp is not yet firmly committed through a purchase order or other agreement.

As part of the March 2006 acquisition of PacifiCorp, MEHC and PacifiCorp made a number of commitments to the state regulatory commissions in all six states in which PacifiCorp has retail customers. These commitments are generally being implemented over several years following the acquisition and are subject to subsequent regulatory review and approval. Outstanding commitments as of December 31, 2008 include:

- Approximately $812 million in investments in emissions reduction technology for PacifiCorp's existing coal-fired generating facilities. Through December 31, 2008, PacifiCorp had spent a total of $496 million, including non-cash equity AFUDC, on these emissions reduction projects and expects to spend in excess of the original commitment due to higher commodity inflation experienced on the planned investments.
- Approximately $520 million in investments (including both capital and operating expense commitments) in PacifiCorp's transmission and distribution system that would enhance reliability, facilitate the receipt of renewable resources and enable further system optimization. Through December 31, 2008, PacifiCorp had spent a total of $224 million in capital expenditures, including non-cash equity AFUDC, in support of this commitment, and has announced the transmission expansion project discussed below.

The Energy Gateway Transmission Expansion Project is an investment plan to build approximately 2,000 miles of new high-voltage transmission lines, primarily in Wyoming, Utah, Idaho, Oregon and the desert Southwest. The plan, with an estimated cost exceeding $6.1 billion, includes projects that will address customer load growth, improve system reliability and deliver energy from new wind-powered and other renewable generating resources throughout PacifiCorp's six-state service area and the Western United States. Certain transmission segments associated with this plan are expected to be placed in service beginning in 2010, with other segments placed in service through 2018, depending on siting, permitting and construction schedules.

*Transmission*

PacifiCorp has agreements for the right to transmit electricity over other entities' transmission lines to facilitate delivery to PacifiCorp's customers.

*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.

Net rent expense was $25 million and $29 million during the years ended December 31, 2008 and 2007, respectively.

*Other*

PacifiCorp has purchase obligations related to equipment maintenance and various other service and maintenance agreements.

**(14) Preferred Stock**

PacifiCorp's preferred stock, not subject to mandatory redemption, was as follows as of December 31 (shares in thousands, dollars in millions, except per share amounts):

| | Redemption Price Per Share | 2008 Shares | 2008 Amount | 2007 Shares | 2007 Amount |
|---|---|---|---|---|---|
| Series: | | | | | |
| Serial Preferred, $100 stated value, 3,500 shares authorized | | | | | |
| 4.52% to 4.72% | $102.3 to $103.5 | 157 | $ 15 | 157 | $ 15 |
| 5.00% to 5.40% | $100.0 to $101.0 | 108 | 10 | 108 | 10 |
| 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 |
| | | 415 | $ 41 | 415 | $ 41 |

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 as of December 31, 2008 and 2007.

## (15) Common Shareholder's Equity

*Appropriated Retained Earnings*

In accordance with the requirements of certain hydroelectric relicensing projects, as of December 31, 2008 and 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 MEHC's March 2006 acquisition of PacifiCorp 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.

As of December 31, 2008, 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. From January 1, 2009 through December 31, 2009 the minimum level of common equity required by this commitment is 47.25%. After December 31, 2009, 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 MEHC's March 2006 acquisition of PacifiCorp as common equity. As of December 31, 2008, PacifiCorp's actual common stock equity percentage, as calculated under this measure, was 52.6%, and PacifiCorp had $945 million available to dividend.

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. As of December 31, 2008, PacifiCorp's unsecured debt rating was A- by Standard & Poor's Rating Services, BBB+ by 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 8 and 9.

**(16) Related-Party Transactions**

*Transactions with MEHC*

PacifiCorp has an intercompany administration services agreement with its indirect parent company, MEHC. Services provided by PacifiCorp and charged to affiliates relate primarily to administrative services, financial statement preparation and direct-assigned employees. These receivables were $1 million and $- million as of December 31, 2008 and 2007, respectively. Services provided by affiliates and charged to PacifiCorp relate primarily to the administrative services provided under the intercompany administrative services agreement among MEHC and its affiliates. These expenses totaled $9 million during each of the years ended December 31, 2008 and 2007. These payables were $1 million as of December 31, 2008 and 2007.

PacifiCorp engages in various transactions with several of its affiliated companies in the ordinary course of business. Services provided by affiliates in the ordinary course of business and charged to PacifiCorp relate primarily to the transportation of natural gas and relocation services. These expenses totaled $6 million and $5 million during the years ended December 31, 2008 and 2007, respectively. These payables were $2 million and $1 million as of December 31, 2008 and 2007, respectively.

Berkshire Hathaway, PacifiCorp's ultimate parent company, has an ownership interest in Burlington Northern Santa Fe Railway ("BNSF"). PacifiCorp has long-term transportation contracts with BNSF. Transportation costs under these contracts were $32 million and $31 million during the years ended December 31, 2008 and 2007, respectively. As of December 31, 2008 and 2007, PacifiCorp had $2 million of accounts payable to BNSF outstanding under these contracts, including indirect payables related to a jointly owned plant.

PacifiCorp participates 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, 2009. Premium expenses were $7 million during each of the years ended December 31, 2008 and 2007. Prepayments to MISL were $2 million as of December 31, 2008 and 2007. Receivables for claims were $7 million and $11 million as of December 31, 2008 and 2007, respectively.

PacifiCorp is party to a tax-sharing agreement and is part of the Berkshire Hathaway United States federal income tax return. As of December 31, 2008 and 2007, prepayments included $42 million and $22 million, respectively, of income taxes receivable from MEHC.

*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 as of December 31, 2008 and 2007. Services provided by subsidiaries and charged to PacifiCorp primarily related to coal purchases. These payables were $14 million and $9 million as of December 31, 2008 and 2007, respectively. Expenses for these coal purchases were $141 million and $102 million for the years ended December 31, 2008 and 2007, respectively.

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, 2008 and 2007, affiliated notes receivable from unconsolidated subsidiaries were $21 million and $26 million, respectively, including interest.

**(17) Supplemental Cash Flows Information**

The summary of supplemental cash flows information is as follows (in millions):

| | Years Ended December 31, | |
|---|---|---|
| | **2008** | **2007** |
| Interest paid, net of amounts capitalized | $ 280 | $ 251 |
| Income taxes (received) paid, net | $ (52) | $ 152 |
| **Supplemental disclosure of non-cash investing and financing activities:** | | |
| Utility plant additions in accounts payable | $ 398 | $ 103 |
| Utility plant additions acquired under capital lease obligations | $ 17 | $ - |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## 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<br>(a) | Unrealized Gains and Losses on Available-for-Sale Securities<br>(b) | Minimum Pension Liability adjustment (net amount)<br>(c) | Foreign Currency Hedges<br>(d) | Other Adjustments<br>(e) |
|---|---|---|---|---|---|
| 1 | Balance of Account 219 at Beginning of Preceding Year | 9,866 | | | ( 5,939,253) |
| 2 | Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income | | | | |
| 3 | Preceding Quarter/Year to Date Changes in Fair Value | 31,088 | | | 2,381,915 |
| 4 | Total (lines 2 and 3) | 31,088 | | | 2,381,915 |
| 5 | Balance of Account 219 at End of Preceding Quarter/Year | 40,954 | | | ( 3,557,338) |
| 6 | Balance of Account 219 at Beginning of Current Year | 40,954 | | | ( 3,557,338) |
| 7 | Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income | | | | |
| 8 | Current Quarter/Year to Date Changes in Fair Value | ( 171,723) | | | 1,137,427 |
| 9 | Total (lines 7 and 8) | ( 171,723) | | | 1,137,427 |
| 10 | Balance of Account 219 at End of Current Quarter/Year | ( 130,769) | | | ( 2,419,911) |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

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

| Line No. | Other Cash Flow Hedges Interest Rate Swaps<br>(f) | Other Cash Flow Hedges [Specify]<br>(g) | Totals for each category of items recorded in Account 219<br>(h) | Net Income (Carried Forward from Page 117, Line 78)<br>(i) | Total Comprehensive Income<br>(j) |
|---|---|---|---|---|---|
| 1 | | 2,047,252 | ( 3,882,135) | | |
| 2 | | ( 2,047,252) | ( 2,047,252) | | |
| 3 | | | 2,413,003 | | |
| 4 | | ( 2,047,252) | 365,751 | 438,888,867 | 439,254,618 |
| 5 | | | ( 3,516,384) | | |
| 6 | | | ( 3,516,384) | | |
| 7 | | | | | |
| 8 | | | 965,704 | | |
| 9 | | | 965,704 | 458,282,904 | 459,248,608 |
| 10 | | | ( 2,550,680) | | |

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

Unrealized loss on available-for-sale securities of ($210,751) less tax of $79,982 netting to ($130,769).

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

Unrecognized amounts on retirement benefits of ($3,900,000) less tax of $1,480,089 netting to ($2,419,911).

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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

| Line No. | Classification<br>(a) | Total Company for the Current Year/Quarter Ended<br>(b) | Electric<br>(c) |
|---|---|---|---|
| 1 | Utility Plant | | |
| 2 | In Service | | |
| 3 | Plant in Service (Classified) | 17,858,244,918 | 17,858,244,918 |
| 4 | Property Under Capital Leases | 65,742,757 | 65,742,757 |
| 5 | Plant Purchased or Sold | 302,819,070 | 302,819,070 |
| 6 | Completed Construction not Classified | 63,878,843 | 63,878,843 |
| 7 | Experimental Plant Unclassified | | |
| 8 | Total (3 thru 7) | 18,290,685,588 | 18,290,685,588 |
| 9 | Leased to Others | | |
| 10 | Held for Future Use | 15,074,557 | 15,074,557 |
| 11 | Construction Work in Progress | 1,208,785,536 | 1,208,785,536 |
| 12 | Acquisition Adjustments | 157,193,780 | 157,193,780 |
| 13 | Total Utility Plant (8 thru 12) | 19,671,739,461 | 19,671,739,461 |
| 14 | Accum Prov for Depr, Amort, & Depl | 6,848,927,351 | 6,848,927,351 |
| 15 | Net Utility Plant (13 less 14) | 12,822,812,110 | 12,822,812,110 |
| 16 | Detail of Accum Prov for Depr, Amort & Depl | | |
| 17 | In Service: | | |
| 18 | Depreciation | 6,343,121,197 | 6,343,121,197 |
| 19 | Amort & Depl of Producing Nat Gas Land/Land Right | | |
| 20 | Amort of Underground Storage Land/Land Rights | | |
| 21 | Amort of Other Utility Plant | 414,958,634 | 414,958,634 |
| 22 | Total In Service (18 thru 21) | 6,758,079,831 | 6,758,079,831 |
| 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 | 90,847,520 | 90,847,520 |
| 33 | Total Accum Prov (equals 14) (22,26,30,31,32) | 6,848,927,351 | 6,848,927,351 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

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

| Gas<br>(d) | Other (Specify)<br>(e) | Other (Specify)<br>(f) | Other (Specify)<br>(g) | Common<br>(h) | Line No. |
|---|---|---|---|---|---|
| | | | | | 1 |
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**Schedule Page: 200 Line No.: 18 Column: c**

Depreciation is comprised of:

| | |
|---|---|
| Depreciation | $6,309,809,795 |
| Depletion | 33,311,402 |
| Total | $6,343,121,197 |

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(Next Page is 204)

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

| Line No. | Account (a) | Balance Beginning of Year (b) | Additions (c) |
|---|---|---|---|
| 1 | 1. INTANGIBLE PLANT | | |
| 2 | (301) Organization | | |
| 3 | (302) Franchises and Consents | 115,670,811 | 50,216,836 |
| 4 | (303) Miscellaneous Intangible Plant | 555,278,797 | 30,887,832 |
| 5 | TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4) | 670,949,608 | 81,104,668 |
| 6 | 2. PRODUCTION PLANT | | |
| 7 | A. Steam Production Plant | | |
| 8 | (310) Land and Land Rights | 94,677,729 | 1,168,771 |
| 9 | (311) Structures and Improvements | 803,481,836 | 18,092,182 |
| 10 | (312) Boiler Plant Equipment | 2,842,150,285 | 241,428,185 |
| 11 | (313) Engines and Engine-Driven Generators | | |
| 12 | (314) Turbogenerator Units | 754,869,133 | 45,948,270 |
| 13 | (315) Accessory Electric Equipment | 340,742,715 | 22,233,810 |
| 14 | (316) Misc. Power Plant Equipment | 25,907,698 | 334,482 |
| 15 | (317) Asset Retirement Costs for Steam Production | 26,574,784 | 1,379,350 |
| 16 | TOTAL Steam Production Plant (Enter Total of lines 8 thru 15) | 4,888,404,180 | 330,585,050 |
| 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 | 19,692,547 | 288 |
| 28 | (331) Structures and Improvements | 83,912,040 | 2,812,430 |
| 29 | (332) Reservoirs, Dams, and Waterways | 279,983,821 | 16,447,223 |
| 30 | (333) Water Wheels, Turbines, and Generators | 90,548,710 | 12,670,210 |
| 31 | (334) Accessory Electric Equipment | 43,143,055 | 10,213,031 |
| 32 | (335) Misc. Power PLant Equipment | 2,564,625 | 14,624 |
| 33 | (336) Roads, Railroads, and Bridges | 13,940,904 | 820,767 |
| 34 | (337) Asset Retirement Costs for Hydraulic Production | | |
| 35 | TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34) | 533,785,702 | 42,978,573 |
| 36 | D. Other Production Plant | | |
| 37 | (340) Land and Land Rights | 21,542,670 | 247 |
| 38 | (341) Structures and Improvements | 112,490,790 | 1,295,742 |
| 39 | (342) Fuel Holders, Products, and Accessories | 8,976,320 | -31,431 |
| 40 | (343) Prime Movers | 892,403,545 | 778,331,190 |
| 41 | (344) Generators | 223,358,160 | 24,869 |
| 42 | (345) Accessory Electric Equipment | 115,873,753 | 8,054 |
| 43 | (346) Misc. Power Plant Equipment | 6,664,886 | |
| 44 | (347) Asset Retirement Costs for Other Production | 1,303,579 | 735,093 |
| 45 | TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44) | 1,382,613,703 | 780,363,764 |
| 46 | TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45) | 6,804,803,585 | 1,153,927,387 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

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

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

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

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

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

| Retirements<br>(d) | Adjustments<br>(e) | Transfers<br>(f) | Balance at End of Year<br>(g) | | Line No. |
|---|---|---|---|---|---|
| | | | | | 1 |
| | | | | | 2 |
| 3,795,871 | | | 162,091,776 | | 3 |
| 26,960,560 | | -52,140 | 559,153,929 | | 4 |
| 30,756,431 | | -52,140 | 721,245,705 | | 5 |
| | | | | | 6 |
| | | | | | 7 |
| | | | 95,846,500 | | 8 |
| 4,080,804 | | -1,544,526 | 815,948,688 | | 9 |
| 88,317,049 | | -16,253,788 | 2,979,007,633 | | 10 |
| | | | | | 11 |
| 11,694,118 | | 15,232,091 | 804,355,376 | | 12 |
| 958,905 | | 427,808 | 362,445,428 | | 13 |
| 89,688 | | 308,400 | 26,460,892 | | 14 |
| | -699,980 | | 27,254,154 | | 15 |
| 105,140,564 | -699,980 | -1,830,015 | 5,111,318,671 | | 16 |
| | | | | | 17 |
| | | | | | 18 |
| | | | | | 19 |
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| | | | | | 21 |
| | | | | | 22 |
| | | | | | 23 |
| | | | | | 24 |
| | | | | | 25 |
| | | | | | 26 |
| | | | 19,692,835 | | 27 |
| 152,650 | | 495,038 | 87,066,858 | | 28 |
| 240,070 | | | 296,190,974 | | 29 |
| 458,271 | | 116,409 | 102,877,058 | | 30 |
| 645,786 | | -488,386 | 52,221,914 | | 31 |
| 26,461 | | -174,819 | 2,377,969 | | 32 |
| 34,231 | | | 14,727,440 | | 33 |
| | | | | | 34 |
| 1,557,469 | | -51,758 | 575,155,048 | | 35 |
| | | | | | 36 |
| | | | 21,542,917 | | 37 |
| 121,181 | | -5,473,946 | 108,191,405 | | 38 |
| 102,180 | | 351,555 | 9,194,264 | | 39 |
| 4,902,973 | | -27,612,667 | 1,638,219,095 | | 40 |
| 11,373 | | 11,850,056 | 235,221,712 | | 41 |
| 164,618 | | 19,327,489 | 135,044,678 | | 42 |
| | | 519,133 | 7,184,019 | | 43 |
| | | | 2,038,672 | | 44 |
| 5,302,325 | | -1,038,380 | 2,156,636,762 | | 45 |
| 112,000,358 | -699,980 | -2,920,153 | 7,843,110,481 | | 46 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

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

| Line No. | Account<br>(a) | Balance Beginning of Year<br>(b) | Additions<br>(c) |
|---|---|---|---|
| 47 | 3. TRANSMISSION PLANT | | |
| 48 | (350) Land and Land Rights | 88,585,565 | 6,900,063 |
| 49 | (352) Structures and Improvements | 63,744,997 | 709,228 |
| 50 | (353) Station Equipment | 1,029,270,485 | 139,174,258 |
| 51 | (354) Towers and Fixtures | 434,468,188 | -994,097 |
| 52 | (355) Poles and Fixtures | 532,740,254 | 38,815,670 |
| 53 | (356) Overhead Conductors and Devices | 703,734,651 | 31,838,803 |
| 54 | (357) Underground Conduit | 3,277,612 | 3,065 |
| 55 | (358) Underground Conductors and Devices | 7,365,512 | |
| 56 | (359) Roads and Trails | 11,472,227 | 62,857 |
| 57 | (359.1) Asset Retirement Costs for Transmission Plant | | |
| 58 | TOTAL Transmission Plant (Enter Total of lines 48 thru 57) | 2,874,659,491 | 216,509,847 |
| 59 | 4. DISTRIBUTION PLANT | | |
| 60 | (360) Land and Land Rights | 45,675,442 | 1,217,841 |
| 61 | (361) Structures and Improvements | 51,355,986 | 182,337 |
| 62 | (362) Station Equipment | 683,925,359 | 60,584,106 |
| 63 | (363) Storage Battery Equipment | 1,457,804 | |
| 64 | (364) Poles, Towers, and Fixtures | 844,025,721 | 36,311,658 |
| 65 | (365) Overhead Conductors and Devices | 607,741,213 | 17,936,500 |
| 66 | (366) Underground Conduit | 270,012,305 | 10,883,966 |
| 67 | (367) Underground Conductors and Devices | 649,509,858 | 30,452,909 |
| 68 | (368) Line Transformers | 974,004,458 | 58,669,335 |
| 69 | (369) Services | 503,373,333 | 33,206,213 |
| 70 | (370) Meters | 184,941,478 | 29,272,089 |
| 71 | (371) Installations on Customer Premises | 8,860,604 | 46,571 |
| 72 | (372) Leased Property on Customer Premises | 49,658 | |
| 73 | (373) Street Lighting and Signal Systems | 59,329,699 | 2,926,943 |
| 74 | (374) Asset Retirement Costs for Distribution Plant | 374,403 | 124,782 |
| 75 | TOTAL Distribution Plant (Enter Total of lines 60 thru 74) | 4,884,637,321 | 281,815,250 |
| 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 | 15,283,942 | 810,324 |
| 87 | (390) Structures and Improvements | 226,824,150 | 11,047,415 |
| 88 | (391) Office Furniture and Equipment | 96,245,673 | 11,426,063 |
| 89 | (392) Transportation Equipment | 95,395,892 | 7,100,947 |
| 90 | (393) Stores Equipment | 13,453,276 | 852,926 |
| 91 | (394) Tools, Shop and Garage Equipment | 62,541,713 | 2,751,842 |
| 92 | (395) Laboratory Equipment | 40,187,183 | 1,271,090 |
| 93 | (396) Power Operated Equipment | 122,290,881 | 10,536,787 |
| 94 | (397) Communication Equipment | 241,073,068 | 14,139,432 |
| 95 | (398) Miscellaneous Equipment | 5,930,894 | 401,068 |
| 96 | SUBTOTAL (Enter Total of lines 86 thru 95) | 919,226,672 | 60,337,894 |
| 97 | (399) Other Tangible Property | 263,000,141 | 14,929,866 |
| 98 | (399.1) Asset Retirement Costs for General Plant | 39,748 | |
| 99 | TOTAL General Plant (Enter Total of lines 96, 97 and 98) | 1,182,266,561 | 75,267,760 |
| 100 | TOTAL (Accounts 101 and 106) | 16,417,316,566 | 1,808,624,912 |
| 101 | (102) Electric Plant Purchased (See Instr. 8) | | 302,819,070 |
| 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) | 16,417,338,424 | 2,111,443,982 |

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 |
| 139,664 | | 4,591 | 95,350,555 | | 48 |
| 87,938 | | 6,330,330 | 70,696,617 | | 49 |
| 13,513,612 | | -6,066,842 | 1,148,864,289 | | 50 |
| 1,064,887 | | 1,149,788 | 433,558,992 | | 51 |
| 8,726,292 | | -9,191,373 | 553,638,259 | | 52 |
| 13,052,979 | | 7,746,559 | 730,267,034 | | 53 |
| 2,206 | | -68,889 | 3,209,582 | | 54 |
| | | 124,663 | 7,490,175 | | 55 |
| | | -81,637 | 11,453,447 | | 56 |
| | | | | | 57 |
| 36,587,578 | | -52,810 | 3,054,528,950 | | 58 |
| | | | | | 59 |
| 366,520 | | | 46,526,763 | | 60 |
| 52,057 | | 6,868,201 | 58,354,467 | | 61 |
| 5,415,412 | | -7,307,055 | 731,786,998 | | 62 |
| | | | 1,457,804 | | 63 |
| 6,950,928 | | 148,492 | 873,534,943 | | 64 |
| 5,524,254 | | 21,512 | 620,174,971 | | 65 |
| 982,765 | | | 279,913,506 | | 66 |
| 2,499,032 | | | 677,463,735 | | 67 |
| 9,570,919 | | 17,425 | 1,023,120,299 | | 68 |
| 1,291,443 | | | 535,288,103 | | 69 |
| 26,871,892 | | 217,056 | 187,558,731 | | 70 |
| 93,326 | | | 8,813,849 | | 71 |
| 49,658 | | | | | 72 |
| 760,504 | | | 61,496,138 | | 73 |
| | | | 499,185 | | 74 |
| 60,428,710 | | -34,369 | 5,105,989,492 | | 75 |
| | | | | | 76 |
| | | | | | 77 |
| | | | | | 78 |
| | | | | | 79 |
| | | | | | 80 |
| | | | | | 81 |
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| | | | | | 83 |
| | | | | | 84 |
| | | | | | 85 |
| | | | 16,094,266 | | 86 |
| 8,275,694 | | -108,486 | 229,487,385 | | 87 |
| 18,931,114 | | 311,386 | 89,052,008 | | 88 |
| 2,927,225 | | -206,832 | 99,362,782 | | 89 |
| 862,587 | | 200,725 | 13,644,340 | | 90 |
| 3,122,992 | | 589,743 | 62,760,306 | | 91 |
| 2,629,230 | | 144,168 | 38,973,211 | | 92 |
| 6,670,104 | | 315,928 | 126,473,492 | | 93 |
| 14,787,436 | | 1,486,536 | 241,911,600 | | 94 |
| 171,403 | | 196,523 | 6,357,082 | | 95 |
| 58,377,785 | | 2,929,691 | 924,116,472 | | 96 |
| 4,748,218 | -178,889 | 90,013 | 273,092,913 | | 97 |
| | | | 39,748 | | 98 |
| 63,126,003 | -178,889 | 3,019,704 | 1,197,249,133 | | 99 |
| 302,899,080 | -878,869 | -39,768 | 17,922,123,761 | | 100 |
| | | | 302,819,070 | | 101 |
| | | 21,858 | | | 102 |
| | | | | | 103 |
| 302,899,080 | -878,869 | -61,626 | 18,224,942,831 | | 104 |

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

| Account | Description (a) | Balance 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 | 52,550,647 | - | - | - | - | 52,550,647 |
| 39930 | Structures | 39,600,837 | 791,470 | (7,146) | - | - | 40,385,161 |
| 39941 | Surface - Plant Equipment | 11,882,614 | 464,604 | (166,338) | - | - | 12,180,880 |
| 39944 | Surface - Electric Power Facilities | 3,424,575 | - | - | - | - | 3,424,575 |
| 39945 | Underground - Coal Mine Equipment | 58,966,142 | 9,527,336 | (3,357,384) | - | 391,745 | 65,527,839 |
| 39946 | Longwall Shields | 17,699,562 | - | - | - | - | 17,699,562 |
| 39947 | Longwall Equipment | 10,786,602 | - | (133,830) | - | - | 10,652,772 |
| 39948 | Mainline Extension | 16,528,462 | 940,460 | (467,610) | - | - | 17,001,312 |
| 39949 | Section Extension | 3,935,855 | 922,423 | (163,205) | - | - | 4,695,073 |
| 39951 | Vehicles | 1,115,967 | - | (27,420) | - | 91,872 | 1,180,419 |
| 39952 | Heavy Construction Equipment | 4,842,225 | 356,891 | (38,310) | - | - | 5,160,806 |
| 39960 | Miscellaneous General Equipment | 2,233,419 | 590,998 | (315,652) | - | (391,745) | 2,117,020 |
| 39961 | Computers - Mainframe | 650,464 | 38,630 | (71,323) | - | (1,859) | 615,912 |
| 39970 | Mine Development and Road Extension | 35,542,729 | 1,297,054 | - | - | - | 36,839,783 |
| 399915 | Coal Mine Asset Retirement Obligations | 605,125 | - | - | (178,889) | - | 426,236 |
| | Total Plant Used in Mining Activities | $ 263,000,141 | $ 14,929,866 | $ (4,748,218) | $ (178,889) | $ 90,013 | $ 273,092,913 |

**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.: 101 Column: c**

On September 15, 2008, after having received the required regulatory approvals, PacifiCorp acquired from TNA Merchant Projects, Inc., an affiliate of Suez Energy North America, Inc., 100% of the equity interests of Chehalis Power Generating, LLC, an entity owning a 520-megawatt ("MW") natural gas-fired generating plant located in Chehalis, Washington. The total cash purchase price was $308 million and the estimated fair value of the acquired entity was primarily allocated to the plant. Chehalis Power Generating, LLC was merged into PacifiCorp immediately following the acquisition. The results of the plant's operations have been included in PacifiCorp's Financial Statements since the acquisition date.

In February 2009, PacifiCorp filed with the FERC under docket number AC09-41-000 a request to clear account 102 Electric Plant Purchased or Sold, for costs incurred to acquire the 520-MW natural gas-fired Chehalis generating plant.

**Schedule Page: 204 Line No.: 102 Column: f**

In April 2008, the FERC approved the journal entries called for by the Uniform System of Accounts for the Upper Beaver Hydroelectric Project, which was sold to the City of Beaver, Utah in September 2007. For further information, refer to Important Changes During The Quarter/Year, Item 3 included in this Form No. 1.

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(Next Page is 214)

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/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 | 2010 | 746,268 |
| 6 | White Rock Substation | 2007 | 2009 | 505,024 |
| 7 | Wild Horse Wind Plant | 2007 | 2016 | 6,763,094 |
| 8 | Twelve Mile Wind Plant | 2007 | 2016 | 2,160,207 |
| 9 | Jumbers Point Substation | 2008 | 2012 | 1,173,276 |
| 10 | | | | |
| 11 | Miscellaneous, each under $250,000: | | | 527,776 |
| 12 | | | | |
| 13 | | | | |
| 14 | | | | |
| 15 | | | | |
| 16 | | | | |
| 17 | | | | |
| 18 | | | | |
| 19 | | | | |
| 20 | | | | |
| 21 | Other Property: | | | |
| 22 | | | | |
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| 44 | | | | |
| 45 | | | | |
| 46 | | | | |
| 47 | Total | | | 15,074,557 |

**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.: 7 Column: c**

Land purchased for wind farms with an estimated construction date of 2016 or before subject to the timing of completion of the Energy Gateway Transmission Expansion Project.

**Schedule Page: 214 Line No.: 8 Column: c**

Land purchased for wind farms with an estimated construction date of 2016 or before subject to the timing of completion of the Energy Gateway Transmission Expansion Project.

**Schedule Page: 214 Line No.: 11 Column: c**

Various dates and plans.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

| Line No. | Description of Project (a) | Construction work in progress - Electric (Account 107) (b) |
|---|---|---|
| 1 | Intangible: | |
| 2 | Klamath Relicensing | 56,574,157 |
| 3 | Transmission Scheduling Project KWH | 3,464,308 |
| 4 | C&T TrIP II Energy Trading Systems | 3,074,257 |
| 5 | SAP License and Maintenance Enhancements | 2,144,405 |
| 6 | | |
| 7 | Production: | |
| 8 | Rolling Hills Wind Plant (99 MW) | 196,499,054 |
| 9 | High Plains Wind Plant (99 MW) | 116,484,099 |
| 10 | Dave Johnston U3 SO2 & PM Emission Control Upgrades | 114,821,152 |
| 11 | Glenrock III Wind Plant (39 MW) | 80,034,026 |
| 12 | Dunlap II Wind Plant | 26,341,809 |
| 13 | Dave Johnston U4 SO2 & PM Emission Control Upgrades | 25,666,763 |
| 14 | Dunlap I Wind Plant | 20,772,737 |
| 15 | North Umpqua Relicensing Implementation | 14,079,563 |
| 16 | Blundell Project | 12,329,806 |
| 17 | Lewis River Relicensing Implementation | 10,219,999 |
| 18 | Huntington U1 Clean Air - PM | 9,758,572 |
| 19 | Dave Johnston U4 - Boiler/Turbine Controls | 7,228,398 |
| 20 | Dave Johnston U4 - Boiler Economizer/Low Temp SH Upgrade | 6,400,603 |
| 21 | Hunter U2 Clean Air-PM | 5,777,416 |
| 22 | Hunter U1 Turbine Upgrade HP/IP/LP | 4,335,554 |
| 23 | Huntington Water Efficiency Management | 4,266,531 |
| 24 | Jim Bridger U3 S02 & PM Emission Control Upgrades | 3,897,890 |
| 25 | Dave Johnston U4 - Replace Reheater | 3,274,339 |
| 26 | Jim Bridger U1 S02 & PM Emission Control Upgrades | 3,143,669 |
| 27 | Dave Johnston U4 NOx | 2,416,291 |
| 28 | Huntington U2 Steam Coil Air Preheaters | 2,405,371 |
| 29 | Jim Bridger Soda Liquor Storage | 2,184,437 |
| 30 | Huntington U1 Turbine Upgrade HP/IP/LP | 1,849,881 |
| 31 | Jim Bridger U1 Turbine Upgrade HP/IP/LP | 1,825,985 |
| 32 | Jim Bridger U2 S02 & PM Emission Control Upgrades | 1,713,133 |
| 33 | Ashton Dam Seepage Control | 1,709,799 |
| 34 | NERC/CIPS Security Remediation 2008 | 1,696,603 |
| 35 | Jim Bridger U1 Generator Rewind | 1,670,273 |
| 36 | Carbon - Fly Ash Handling System | 1,644,761 |
| 37 | Huntington Security - NERC/CIPS Physical Security | 1,627,713 |
| 38 | Dave Johnston - Install Fire Protection Pump | 1,579,895 |
| 39 | Hunter U2 Turbine Upgrade HP/IP/LP | 1,444,273 |
| 40 | Jim Bridger Fan Bay Road Paving/Regrade 07 | 1,391,983 |
| 41 | Currant Creek Block 2 Development | 1,282,345 |
| 42 | Dave Johnston U4 - Replace Air Heater Baskets | 1,264,784 |
| 43 | TOTAL | 1,208,785,536 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

| Line No. | Description of Project<br>(a) | Construction work in progress - Electric (Account 107)<br>(b) |
|---|---|---|
| 1 | Jim Bridger U2 Reheater Outlet Terminal Tubes | 1,181,351 |
| 2 | Dave Johnston U3 Mercury CEMS | 1,065,761 |
| 3 | Naughton U3 OH Generator Rotor Replacement | 1,038,161 |
| 4 | Dave Johnston - Coal Load-In/Tripper Washdown System | 1,038,029 |
| 5 | Dave Johnston - Replace/Expand CET Shop | 1,006,469 |
| 6 | | |
| 7 | Transmission: | |
| 8 | Populus-Terminal: Dbl Ckt 345 kV Transmission Line | 127,889,642 |
| 9 | Oquirrh New 345-138kV Substation | 12,342,339 |
| 10 | Chappel Creek 230KV Cimarex Energy | 10,913,534 |
| 11 | Camp Williams Static VAR Compensator Installation | 8,735,215 |
| 12 | Line 37 Conv to 115kV Bld Nickel Mt Sub | 8,654,405 |
| 13 | Glenrock Wind Interconnection | 6,521,882 |
| 14 | Mona-Oquirrh Line | 6,232,249 |
| 15 | Dave Johnston Bridger Midpoint 500kV Line | 6,001,729 |
| 16 | Three Peaks Sub: Install 345 kV Sub | 5,783,381 |
| 17 | Wine Country New 230-115kV Sub | 5,743,968 |
| 18 | Copco II Sub Repl Exist 115-69kV Trnsfmr | 5,470,516 |
| 19 | Bridger Mona 500kV Line | 3,479,206 |
| 20 | Three Mile Knoll Sub: New 345-138kV Sub | 3,433,694 |
| 21 | Upper Green River Basin - Jonah Field & Paradise Subs/Lines | 3,265,143 |
| 22 | Mona Substation Instl New 345kV Cap Bank | 1,955,454 |
| 23 | Shute Creek to Mona System Upgrade | 1,920,659 |
| 24 | St George-Red Butte 138kV Line | 1,741,682 |
| 25 | McClelland-Emigration Tap 1.4Mi OH Line | 1,550,386 |
| 26 | California-Oregon Intertie Transfer Capability Incr | 1,385,277 |
| 27 | Walla Walla Midway 230kV Line | 1,130,512 |
| 28 | Malin Sub CKB Repl ITE 500kV CKB4591 | 1,099,550 |
| 29 | Jim Bridger - Repel RAS A&B Scheme Project | 2,014,568 |
| 30 | | |
| 31 | Distribution: | |
| 32 | Yew Avenue - Constuct New Sub (Tetherow) | 9,516,574 |
| 33 | Morrison Creek Sub Construct New Substation | 3,906,254 |
| 34 | Snyderville Add 2nd Transformer | 3,624,765 |
| 35 | Gold Rush New 139-12.5kV 30MVA Sub | 3,497,467 |
| 36 | Shoreline New 138-12.5kV Sub Transf & Fdrs | 2,271,873 |
| 37 | Northeast Instl 2nd 4-12kV Trnsf 4-12kV | 2,097,169 |
| 38 | E Layton Install 2nd 30MVA Trnsmr-Dist | 1,985,847 |
| 39 | Casper WY Automated Meter Reading Project | 1,325,257 |
| 40 | | |
| 41 | General: | |
| 42 | Mobile Radio Replacement Project | 10,870,775 |
| 43 | TOTAL | 1,208,785,536 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

| Line No. | Description of Project (a) | Construction work in progress - Electric (Account 107) (b) |
|---|---|---|
| 1 | Jim Bridger - Repl RAS A&B Scheme Project | 2,014,569 |
| 2 | SAP Hardware and Database | 2,962,077 |
| 3 | Energy West-Business System Upgrade | 1,771,723 |
| 4 | IP Telephony Project | 1,038,215 |
| 5 | | |
| 6 | Miscellaneous Projects each under $1,000,000 | 171,011,575 |
| 7 | | |
| 8 | | |
| 9 | | |
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| 40 | | |
| 41 | | |
| 42 | | |
| 43 | TOTAL | 1,208,785,536 |

***Schedule Page: 216.2 Line No.: 6 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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

**Section A. Balances and Changes During Year**

| Line No. | Item (a) | Total (c+d+e) (b) | Electric Plant in Service (c) | Electric Plant Held for Future Use (d) | Electric Plant Leased to Others (e) |
|---|---|---|---|---|---|
| 1 | Balance Beginning of Year | 6,199,821,444 | 6,199,821,444 | | |
| 2 | Depreciation Provisions for Year, Charged to | | | | |
| 3 | (403) Depreciation Expense | 416,636,387 | 416,636,387 | | |
| 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): | 26,528,751 | 26,528,751 | | |
| 9 | | | | | |
| 10 | TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9) | 443,165,138 | 443,165,138 | | |
| 11 | Net Charges for Plant Retired: | | | | |
| 12 | Book Cost of Plant Retired | 268,449,771 | 268,449,771 | | |
| 13 | Cost of Removal | 45,338,806 | 45,338,806 | | |
| 14 | Salvage (Credit) | 8,783,073 | 8,783,073 | | |
| 15 | TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14) | 305,005,504 | 305,005,504 | | |
| 16 | Other Debit or Cr. Items (Describe, details in footnote): | 5,140,119 | 5,140,119 | | |
| 17 | | | | | |
| 18 | Book Cost or Asset Retirement Costs Retired | | | | |
| 19 | Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18) | 6,343,121,197 | 6,343,121,197 | | |
| | **Section B. Balances at End of Year According to Functional Classification** | | | | |
| 20 | Steam Production | 2,467,561,753 | 2,467,561,753 | | |
| 21 | Nuclear Production | | | | |
| 22 | Hydraulic Production-Conventional | 242,183,351 | 242,183,351 | | |
| 23 | Hydraulic Production-Pumped Storage | | | | |
| 24 | Other Production | 154,698,448 | 154,698,448 | | |
| 25 | Transmission | 1,097,506,323 | 1,097,506,323 | | |
| 26 | Distribution | 1,906,426,138 | 1,906,426,138 | | |
| 27 | Regional Transmission and Market Operation | | | | |
| 28 | General | 474,745,184 | 474,745,184 | | |
| 29 | TOTAL (Enter Total of lines 20 thru 28) | 6,343,121,197 | 6,343,121,197 | | |

***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 | $ | 9,786,263 |
| Account 143.3 Joint Owner Receivable - Depreciation expense billed to Joint Owners | | 280,223 |
| Account 182.3 Other Regulatory Assets | | 1,725,894 |
| Vehicle Depreciation allocated to O&M based on usage activity | | 13,465,822 |
| Account 503.1 Blundell Depletion | | 185,368 |
| Account 503 IGC Depreciation and Amortization | | 1,085,369 |
| Total Other Accounts | | (188) |
| | $ | 26,528,751 |

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

| | | |
|---|---|---|
| Other items including: | $ | 5,140,119 |

- 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 | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

| Line No. | Description of Investment (a) | Date Acquired (b) | Date Of Maturity (c) | Amount of Investment at Beginning of Year (d) |
|---|---|---|---|---|
| 1 | PACIFIC MINERALS, INC | 12/31/1991 | | |
| 2 | Common Stock | | | 1 |
| 3 | Capital Contributions | | | 32,460,000 |
| 4 | Undistributed Earnings | | | 93,410,979 |
| 5 | SUBTOTAL | | | 125,870,980 |
| 6 | | | | |
| 7 | PACIFICORP ENVIRONMENTAL REMEDIATION COMPANY | 8/19/1994 | | |
| 8 | Common Stock | | | 900,000 |
| 9 | Capital Contributions | | | 13,719,625 |
| 10 | Acquisition of Minority Interest | | | 956,888 |
| 11 | Undistributed Subsidiary Earnings | | | 7,567,496 |
| 12 | SUBTOTAL | | | 23,144,009 |
| 13 | | | | |
| 14 | PACIFIC FUTURE GENERATIONS, INC | 9/19/1999 | | |
| 15 | Undistributed Subsidiary Earnings | | | -9,952 |
| 16 | SUBTOTAL | | | -9,952 |
| 17 | | | | |
| 18 | | | | |
| 19 | | | | |
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| 40 | | | | |
| 41 | | | | |
| 42 | Total Cost of Account 123.1 $ 62,679,626 | | TOTAL | 149,005,037 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

| Equity in Subsidiary Earnings of Year (e) | Revenues for Year (f) | Amount of Investment at End of Year (g) | Gain or Loss from Investment Disposed of (h) | Line No. |
|---|---|---|---|---|
| | | | | 1 |
| | | 1 | | 2 |
| | | 47,960,000 | | 3 |
| 8,910,812 | | 102,321,791 | | 4 |
| 8,910,812 | | 150,281,792 | | 5 |
| | | | | 6 |
| | | | | 7 |
| | | 1,000,000 | | 8 |
| | | 13,719,625 | | 9 |
| | | | | 10 |
| -1,905,654 | | 6,518,730 | | 11 |
| -1,905,654 | | 21,238,355 | | 12 |
| | | | | 13 |
| | | | | 14 |
| | | -9,952 | | 15 |
| | | -9,952 | | 16 |
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| | | | | 41 |
| 7,005,158 | | 171,510,195 | | 42 |

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

Reflects $15,500,000 capital contributions from parent company in 2008.

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

As equity earnings on PacifiCorp's investment in Pacific Minerals, Inc. ("PMI") represent intercompany profit in Bridger Coal Company's sales of coal to PacifiCorp, such amounts are not recorded in account 418.1, Equity in Earnings of Subsidiary Companies. Rather, PacifiCorp records PMI's earnings before interest and taxes as an offset to fuel inventory, which is charged to fuel expense as consumed, and records interest and taxes in their respective line items. PMI owns Bridger Coal Company jointly with a subsidiary of Idaho Power Company.

***Schedule Page: 224 Line No.: 8 Column: g***

See footnote on line 10, column g

***Schedule Page: 224 Line No.: 10 Column: g***

PacifiCorp Environmental Remediation Company ("PERCo") became a wholly owned subsidiary of PacifiCorp in April 2007, when PacifiCorp acquired the outstanding 10% minority interest. The acquisition of PERCo's minority interest was allocated to common stock in the amount of $100,000 and undistributed susidiary earnings in the amount of $856,888.

***Schedule Page: 224 Line No.: 11 Column: g***

See footnote on line 10, column g

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(Next Page is 227)

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## MATERIALS AND SUPPLIES

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

| Line No. | Account (a) | Balance Beginning of Year (b) | Balance End of Year (c) | Department or Departments which Use Material (d) |
|---|---|---|---|---|
| 1 | Fuel Stock (Account 151) | 98,334,182 | 136,802,882 | 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) | 53,387,313 | 76,746,318 | Electric |
| 6 | Assigned to - Operations and Maintenance | | | |
| 7 | Production Plant (Estimated) | 74,067,221 | 71,228,040 | Electric |
| 8 | Transmission Plant (Estimated) | 6,228,512 | 497,646 | Electric |
| 9 | Distribution Plant (Estimated) | 11,906,581 | 16,772,938 | Electric |
| 10 | Regional Transmission and Market Operation Plant (Estimated) | | | |
| 11 | Assigned to - Other (provide details in footnote) | 4,460,395 | 4,830,427 | Electric |
| 12 | TOTAL Account 154 (Enter Total of lines 5 thru 11) | 150,050,022 | 170,075,369 | |
| 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) | 248,384,204 | 306,878,251 | |

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

| | |
|---|---|
| Mining M&S | $4,314,408 |
| General Plant M&S | 145,987 |
| | $4,460,395 |

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

| | |
|---|---|
| Mining M&S | $4,656,652 |
| General Plant M&S | 173,775 |
| | $4,830,427 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

| Line No. | Allowances Inventory (Account 158.1) (a) | Current Year No. (b) | Current Year Amt. (c) | 2009 No. (d) | 2009 Amt. (e) |
|---|---|---|---|---|---|
| 1 | Balance-Beginning of Year | 127,064.00 | | 121,095.00 | |
| 2 | | | | | |
| 3 | Acquired During Year: | | | | |
| 4 | Issued (Less Withheld Allow) | | | | |
| 5 | Returned by EPA | | | | |
| 6 | | | | | |
| 7 | | | | | |
| 8 | Purchases/Transfers: | | | | |
| 9 | Chehalis | 4.00 | | | |
| 10 | | | | | |
| 11 | | | | | |
| 12 | | | | | |
| 13 | | | | | |
| 14 | | | | | |
| 15 | Total | 4.00 | | | |
| 16 | | | | | |
| 17 | Relinquished During Year: | | | | |
| 18 | Charges to Account 509 | 80,340.00 | | | |
| 19 | Other: | | | | |
| 20 | | | | | |
| 21 | Cost of Sales/Transfers: | | | | |
| 22 | DTE Coal Services | 2,000.00 | | | |
| 23 | Louis Dreyfus | 12,000.00 | | | |
| 24 | Macquarie | 1,000.00 | | | |
| 25 | NRG | 1,000.00 | | | |
| 26 | Sempra | 5,000.00 | | | |
| 27 | West Valley | 1.00 | | | |
| 28 | Total | 21,001.00 | | | |
| 29 | Balance-End of Year | 25,727.00 | | 121,095.00 | |
| 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 | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

Allowances (Accounts 158.1 and 158.2) (Continued)

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

| 2010 | | 2011 | | Future Years | | Totals | | Line No. |
|---|---|---|---|---|---|---|---|---|
| No. (f) | Amt. (g) | No. (h) | Amt. (i) | No. (j) | Amt. (k) | No. (l) | Amt. (m) | |
| 144,002.00 | | 156,646.00 | | 4,035,429.00 | | 4,584,236.00 | | 1 |
| | | | | | | | | 2 |
| | | | | | | | | 3 |
| | | | | 156,650.00 | | 156,650.00 | | 4 |
| | | | | | | | | 5 |
| | | | | | | | | 6 |
| | | | | | | | | 7 |
| | | | | | | | | 8 |
| | | | | | | 4.00 | | 9 |
| | | | | | | | | 10 |
| | | | | | | | | 11 |
| | | | | | | | | 12 |
| | | | | | | | | 13 |
| | | | | | | | | 14 |
| | | | | | | 4.00 | | 15 |
| | | | | | | | | 16 |
| | | | | | | | | 17 |
| | | | | | | 80,340.00 | | 18 |
| | | | | | | | | 19 |
| | | | | | | | | 20 |
| | | | | | | | | 21 |
| | | | | | | 2,000.00 | | 22 |
| | | | | | | 12,000.00 | | 23 |
| | | | | | | 1,000.00 | | 24 |
| | | | | | | 1,000.00 | | 25 |
| | | | | | | 5,000.00 | | 26 |
| | | | | | | 1.00 | | 27 |
| | | | | | | 21,001.00 | | 28 |
| 144,002.00 | | 156,646.00 | | 4,192,079.00 | | 4,639,549.00 | | 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<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

| Line No. | Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)]<br>(a) | Total Amount of Charges<br>(b) | Costs Recognised During Year<br>(c) | WRITTEN OFF DURING YEAR<br>Account Charged<br>(d) | WRITTEN OFF DURING YEAR<br>Amount<br>(e) | Balance at End of Year<br>(f) |
|---|---|---|---|---|---|---|
| 21 | Unrecovered Plant: Trojan Nuclear | 5,149,185 | | 407 | 1,670,006 | 3,479,179 |
| 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 | 10,439,884 | -42,934 | 407 | 3,437,028 | 6,959,922 |
| 30 | Hydro Electric Plant | | | | | |
| 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 | | | | | |
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| 46 | | | | | | |
| 47 | | | | | | |
| 48 | | | | | | |
| 49 | TOTAL | 15,589,069 | -42,934 | | 5,107,034 | 10,439,101 |

***Schedule Page: 230 Line No.: 29 Column: c***

Represents insurance reimbursements.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## Transmission Service and Generation Interconnection Study Costs

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

| Line No. | Description (a) | Costs Incurred During Period (b) | Account Charged (c) | Reimbursements Received During the Period (d) | Account Credited With Reimbursement (e) |
|---|---|---|---|---|---|
| 1 | **Transmission Studies** | | | | |
| 2 | See Footnote | 3,469 | 561.6 | 3,469 | 456.2 |
| 3 | Aref 421623, 421624 | 21 | 561.6 | 21 | 456.2 |
| 4 | Aref 421615, 421616, 421617 | 21 | 561.6 | 21 | 456.2 |
| 5 | Aref 421618, 421619, 421620 | 35 | 561.6 | 35 | 456.2 |
| 6 | Aref 445313, 445314 | 433 | 561.6 | 433 | 456.2 |
| 7 | Aref 445315, 445316 | 433 | 561.6 | 433 | 456.2 |
| 8 | Aref 444568, 444569 | 648 | 561.6 | 648 | 456.2 |
| 9 | See Footnote | 3,657 | 561.6 | 3,657 | 456.2 |
| 10 | Aref 404233, 404235 | 516 | 561.6 | 516 | 456.2 |
| 11 | Aref 437326 | 618 | 561.6 | 618 | 456.2 |
| 12 | Aref 424140, 424146 | 5,432 | 561.6 | 5,432 | 456.2 |
| 13 | Aref 468656 | 608 | 561.6 | 608 | 456.2 |
| 14 | Aref 466064, 466065 | 145 | 561.6 | 145 | 456.2 |
| 15 | Aref 475248 | 897 | 561.6 | 897 | 456.2 |
| 16 | See Footnote | 4,156 | 561.6 | 4,032 | 456.2 |
| 17 | Aref 466064, 466065 | 822 | 561.6 | 762 | 456.2 |
| 18 | Aref 475248 | 7,838 | 561.6 | 7,838 | 456.2 |
| 19 | See Footnote | 1,663 | 561.6 | 1,663 | 456.2 |
| 20 | Aref 291675, 292491, 292494 | ( 4,930) | 561.6 | | |
| 21 | **Generation Studies** | | | | |
| 22 | GIQ0108 | 93 | 561.7 | 93 | 456.2 |
| 23 | GIQ0071 | 2,031 | 561.7 | 2,031 | 456.2 |
| 24 | GIQ0092 | 14 | 561.7 | 14 | 456.2 |
| 25 | GIQ0080 | 350 | 561.7 | 350 | 456.2 |
| 26 | GIQ0089 | 975 | 561.7 | 975 | 456.2 |
| 27 | GIQ0060, GIQ0061 | 932 | 561.7 | 932 | 456.2 |
| 28 | GIQ0095 | 2,258 | 561.7 | 2,258 | 456.2 |
| 29 | GIQ0134 | 2,036 | 561.7 | 2,036 | 456.2 |
| 30 | GIQ0138 | 40 | 561.7 | 40 | 456.2 |
| 31 | GIQ0139 | 4,477 | 561.7 | 4,477 | 456.2 |
| 32 | GIQ0119 | 1,418 | 561.7 | 1,418 | 456.2 |
| 33 | GIQ0142 | 1,442 | 561.7 | 1,442 | 456.2 |
| 34 | GIQ0143 | 574 | 561.7 | 574 | 456.2 |
| 35 | GIQ0144 | 449 | 561.7 | 449 | 456.2 |
| 36 | GIQ0151 | 5,787 | 561.7 | 5,787 | 456.2 |
| 37 | GIQ0145, GIQ0146, GIQ0147 | 11,447 | 561.7 | 11,447 | 456.2 |
| 38 | GIQ0148 | 1,050 | 561.7 | 1,050 | 456.2 |
| 39 | GIQ0150 | 1,851 | 561.7 | 1,851 | 456.2 |
| 40 | GIQ0152 | 1,037 | 561.7 | 1,037 | 456.2 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/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 428070 | 42 | 561.6 | | |
| 3 | Aref 428102 | 62 | 561.6 | | |
| 4 | Aref 416445 | 83 | 561.6 | | |
| 5 | Aref 445008 | 21 | 561.6 | | |
| 6 | Aref 449867 | 873 | 561.6 | | |
| 7 | Aref 462551 | 569 | 561.6 | | |
| 8 | Aref 464209 | 442 | 561.6 | | |
| 9 | Aref 464233, 464235, 464713 | 474 | 561.6 | | |
| 10 | See Footnote | 1,287 | 561.6 | | |
| 11 | Aref 464721 | 474 | 561.6 | | |
| 12 | Aref 463745, 463754 | 927 | 561.6 | | |
| 13 | Aref 469874 | 194 | 561.6 | | |
| 14 | Aref 470047 | 636 | 561.6 | | |
| 15 | Aref 471741 | 803 | 561.6 | | |
| 16 | Aref 471743 | 5,940 | 561.6 | | |
| 17 | Aref 462551 | 124 | 561.6 | | |
| 18 | Aref 492327 | 5,392 | 561.6 | | |
| 19 | Aref 493092 | 689 | 561.6 | | |
| 20 | Aref 492326 | 686 | 561.6 | | |
| 21 | **Generation Studies** | | | | |
| 22 | GIQ0153 | 1,474 | 561.7 | 1,474 | 456.2 |
| 23 | GIQ0154 | 1,421 | 561.7 | 1,223 | 456.2 |
| 24 | GIQ0155 | 1,049 | 561.7 | 1,049 | 456.2 |
| 25 | GIQ0117, GIQ0118 | 14,291 | 561.7 | 13,751 | 456.2 |
| 26 | GIQ0128 | 16,438 | 561.7 | 16,438 | 456.2 |
| 27 | See Footnote | 2,878 | 561.7 | 2,878 | 456.2 |
| 28 | GIQ0016 | 231 | 561.7 | 231 | 456.2 |
| 29 | GIQ0100 | 10,561 | 561.7 | 10,561 | 456.2 |
| 30 | GIQ0129 | 20,183 | 561.7 | 20,183 | 456.2 |
| 31 | GIQ0164 | 5,412 | 561.7 | 5,412 | 456.2 |
| 32 | GIQ0165 | 293 | 561.7 | 293 | 456.2 |
| 33 | GIQ0162 | 8,989 | 561.7 | 8,989 | 456.2 |
| 34 | GIQ0163 | 14 | 561.7 | 14 | 456.2 |
| 35 | GIQ0112 | 10,859 | 561.7 | 10,859 | 456.2 |
| 36 | GIQ0139 | 3,470 | 561.7 | 3,470 | 456.2 |
| 37 | GIQ0166 | 1,747 | 561.7 | 1,747 | 456.2 |
| 38 | GIQ0167 | 1,794 | 561.7 | 1,794 | 456.2 |
| 39 | GIQ0168 | 2,330 | 561.7 | 2,330 | 456.2 |
| 40 | GIQ0141 | 5,078 | 561.7 | 5,078 | 456.2 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/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 468352, 469874 | 248 | 561.6 | | |
| 3 | Aref 498286 | 2,110 | 561.6 | | |
| 4 | Aref 505517 | 3,484 | 561.6 | | |
| 5 | Aref 507957 | 1,283 | 561.6 | | |
| 6 | Aref 507960 | 4,279 | 561.6 | | |
| 7 | Aref 508134 | 6,930 | 561.6 | | |
| 8 | Aref 508355 | 2,893 | 561.6 | | |
| 9 | Aref 508362 | 3,809 | 561.6 | | |
| 10 | Aref 508370 | 1,159 | 561.6 | | |
| 11 | Aref 523183 | 372 | 561.6 | | |
| 12 | Aref 531024 | 504 | 561.6 | | |
| 13 | Customer Studies Accruals | 20 | 561.6 | | |
| 14 | Aref 313369 | 194 | 107 | | |
| 15 | Aref 432138 | 1,786 | 107 | | |
| 16 | Aref 432141 | 2,456 | 107 | | |
| 17 | Aref 444572 | 21 | 107 | | |
| 18 | Aref 444730 | 21 | 107 | | |
| 19 | Aref 432138, 432141 | 3,117 | 107 | | |
| 20 | Aref 460658 | 298 | 107 | | |
| 21 | **Generation Studies** | | | | |
| 22 | GIQ0093 | 651 | 561.7 | 651 | 456.2 |
| 23 | GIQ0132 | 7,755 | 561.7 | 7,755 | 456.2 |
| 24 | GIQ0169 | 1,799 | 561.7 | 1,799 | 456.2 |
| 25 | GIQ0170 | 405 | 561.7 | 405 | 456.2 |
| 26 | GIQ0171 | 11,131 | 561.7 | 5,281 | 456.2 |
| 27 | GIQ0119 | 14,175 | 561.7 | 14,175 | 456.2 |
| 28 | GIQ0172 | 2,654 | 561.7 | 2,654 | 456.2 |
| 29 | GIQ0173 | 2,116 | 561.7 | 2,116 | 456.2 |
| 30 | GIQ0138 | 2,938 | 561.7 | 2,938 | 456.2 |
| 31 | GIQ0130 | 21,717 | 561.7 | 21,717 | 456.2 |
| 32 | GIQ0135 | 17,158 | 561.7 | 17,158 | 456.2 |
| 33 | GIQ0136 | 14,354 | 561.7 | 14,354 | 456.2 |
| 34 | GIQ0137 | 14,199 | 561.7 | 14,199 | 456.2 |
| 35 | GIQ0174 | 4,683 | 561.7 | 4,539 | 456.2 |
| 36 | GIQ0175 | 5,207 | 561.7 | 4,057 | 456.2 |
| 37 | GIQ0144 | 13,292 | 561.7 | 13,292 | 456.2 |
| 38 | GIQ0143 | 14,966 | 561.7 | 14,966 | 456.2 |
| 39 | GIQ0142 | 16,805 | 561.7 | 16,805 | 456.2 |
| 40 | GIQ0178 | 8,188 | 561.7 | 8,188 | 456.2 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/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 460548 | 1,162 | 107 | | |
| 3 | Aref 460514, 460515, 460516 | 298 | 107 | | |
| 4 | Aref 462538 | 153 | 107 | | |
| 5 | Aref 464208 | 474 | 107 | | |
| 6 | Aref 488835 | 866 | 107 | | |
| 7 | Aref 495604 | 2,671 | 107 | | |
| 8 | Aref 508324 | 2,227 | 107 | | |
| 9 | Aref 508341 | 2,130 | 107 | | |
| 10 | Aref 507939 | 1,647 | 107 | | |
| 11 | Aref 513817 | 1,364 | 107 | | |
| 12 | Aref 516316 | 256 | 107 | | |
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| 21 | **Generation Studies** | | | | |
| 22 | GIQ0190 | 10,695 | 561.7 | 10,695 | 456.2 |
| 23 | GIQ0187 | 24,831 | 561.7 | 24,831 | 456.2 |
| 24 | GIQ0188 | 16,838 | 561.7 | 16,838 | 456.2 |
| 25 | GIQ0177 | 2,230 | 561.7 | 2,230 | 456.2 |
| 26 | GIQ0148 | 38,073 | 561.7 | 38,073 | 456.2 |
| 27 | GIQ0176 | 2,687 | 561.7 | 2,687 | 456.2 |
| 28 | GIQ0189 | 16,140 | 561.7 | 16,140 | 456.2 |
| 29 | GIQ0128 | 15,299 | 561.7 | 15,299 | 456.2 |
| 30 | GIQ0154 | 19,188 | 561.7 | 19,188 | 456.2 |
| 31 | GIQ0192 | 1,111 | 561.7 | 1,111 | 456.2 |
| 32 | GIQ0151 | 7,419 | 561.7 | 7,419 | 456.2 |
| 33 | GIQ0191 | 4,566 | 561.7 | 4,566 | 456.2 |
| 34 | GIQ0194 | 4,846 | 561.7 | 4,846 | 456.2 |
| 35 | GIQ0193 | 26,444 | 561.7 | 26,444 | 456.2 |
| 36 | GIQ0153 | 5,950 | 561.7 | 5,950 | 456.2 |
| 37 | GIQ0145 | 48,213 | 561.7 | 48,213 | 456.2 |
| 38 | GIQ0166 | 5,426 | 561.7 | 5,426 | 456.2 |
| 39 | GIQ0152 | 15,256 | 561.7 | 15,256 | 456.2 |
| 40 | GIQ0150 | 3,219 | 561.7 | 3,219 | 456.2 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/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** | | | | |
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| 20 | | | | | |
| 21 | **Generation Studies** | | | | |
| 22 | GIQ0162 | 7,642 | 561.7 | 7,642 | 456.2 |
| 23 | GIQ0198 | 2,502 | 561.7 | 2,502 | 456.2 |
| 24 | GIQ0199 | 2,078 | 561.7 | 2,078 | 456.2 |
| 25 | GIQ0200 | 1,457 | 561.7 | 1,457 | 456.2 |
| 26 | GIQ0201 | 1,723 | 561.7 | 1,723 | 456.2 |
| 27 | GIQ0195 | 7,598 | 561.7 | 7,598 | 456.2 |
| 28 | GIQ0197 | 7,642 | 561.7 | 7,642 | 456.2 |
| 29 | GIQ0202 | 1,544 | 561.7 | 1,544 | 456.2 |
| 30 | GIQ0204 | 4,469 | 561.7 | 4,469 | 456.2 |
| 31 | GIQ0205 | 2,354 | 561.7 | 2,354 | 456.2 |
| 32 | GIQ0206 | 1,757 | 561.7 | 1,757 | 456.2 |
| 33 | GIQ0212 | 1,564 | 561.7 | 1,564 | 456.2 |
| 34 | GIQ0172 | 15,557 | 561.7 | 15,557 | 456.2 |
| 35 | GIQ0172 | 14,855 | 561.7 | 14,855 | 456.2 |
| 36 | GIQ0210 | 5,091 | 561.7 | 5,091 | 456.2 |
| 37 | GIQ0209 | 9,830 | 561.7 | 9,830 | 456.2 |
| 38 | GIQ0211 | 4,620 | 561.7 | 4,620 | 456.2 |
| 39 | GIQ0176 | 4,349 | 561.7 | 4,349 | 456.2 |
| 40 | GIQ0142 | 5,870 | 561.7 | 5,870 | 456.2 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/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** | | | | |
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| 19 | | | | | |
| 20 | | | | | |
| 21 | **Generation Studies** | | | | |
| 22 | GIQ0143 | 9,912 | 561.7 | 9,912 | 456.2 |
| 23 | GIQ0213 | 9,453 | 561.7 | 9,453 | 456.2 |
| 24 | GIQ0214 | 3,859 | 561.7 | 3,859 | 456.2 |
| 25 | GIQ0215 | 791 | 561.7 | 791 | 456.2 |
| 26 | GIQ0216 | 3,768 | 561.7 | 3,768 | 456.2 |
| 27 | GIQ0130 | 7,882 | 561.7 | 7,882 | 456.2 |
| 28 | GIQ0135 | 6,273 | 561.7 | 6,273 | 456.2 |
| 29 | GIQ0136 | 2,407 | 561.7 | 2,407 | 456.2 |
| 30 | GIQ0137 | 5,642 | 561.7 | 5,642 | 456.2 |
| 31 | GIQ0217 | 6,534 | 561.7 | 6,534 | 456.2 |
| 32 | GIQ0218 | 5,849 | 561.7 | 5,849 | 456.2 |
| 33 | GIQ0219 | 4,799 | 561.7 | 4,799 | 456.2 |
| 34 | GIQ0220 | 12,379 | 561.7 | 12,379 | 456.2 |
| 35 | GIQ0148 | 21,267 | 561.7 | 21,267 | 456.2 |
| 36 | GIQ0221 | 3,982 | 561.7 | 3,982 | 456.2 |
| 37 | GIQ0153 | 22,949 | 561.7 | 22,949 | 456.2 |
| 38 | GIQ0175 | 15,017 | 561.7 | 15,017 | 456.2 |
| 39 | GIQ0208 | 22,541 | 561.7 | 22,541 | 456.2 |
| 40 | GIQ0225 | 5,493 | 561.7 | 5,493 | 456.2 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original (2) [ ] A Resubmission | 03/31/2009 | End of 2008/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** | | | | |
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| 20 | | | | | |
| 21 | **Generation Studies** | | | | |
| 22 | GIQ0226 | 4,318 | 561.7 | 4,318 | 456.2 |
| 23 | GIQ0171 | 6,593 | 561.7 | 6,593 | 456.2 |
| 24 | GIQ0152 | 18,182 | 561.7 | 18,182 | 456.2 |
| 25 | GIQ0227 | 83,882 | 561.7 | 48,432 | 456.2 |
| 26 | GIQ0016 | 13,185 | 561.7 | 13,185 | 456.2 |
| 27 | GIQ0228 | 1,326 | 561.7 | 1,326 | 456.2 |
| 28 | GIQ0229 | 10,311 | 561.7 | 10,311 | 456.2 |
| 29 | GIQ0191 | 5,394 | 561.7 | 5,394 | 456.2 |
| 30 | GIQ0176 | 6,370 | 561.7 | 6,370 | 456.2 |
| 31 | GIQ0166 | 6,693 | 561.7 | 6,693 | 456.2 |
| 32 | GIQ0231 | 22,022 | 561.7 | 22,022 | 456.2 |
| 33 | GIQ0234 | 3,622 | 561.7 | 3,622 | 456.2 |
| 34 | GIQ0178 | 14,277 | 561.7 | 14,277 | 456.2 |
| 35 | GIQ0154 | 9,705 | 561.7 | 9,705 | 456.2 |
| 36 | GIQ0172 | 6,668 | 561.7 | 6,668 | 456.2 |
| 37 | GIQ0173 | 5,606 | 561.7 | 5,606 | 456.2 |
| 38 | GIQ0236 | 11,474 | 561.7 | 11,474 | 456.2 |
| 39 | GIQ0198 | 6,608 | 561.7 | 6,608 | 456.2 |
| 40 | GIQ0199 | 1,649 | 561.7 | 1,649 | 456.2 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/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** | | | | |
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| 20 | | | | | |
| 21 | **Generation Studies** | | | | |
| 22 | GIQ0200 | 2,259 | 561.7 | 2,259 | 456.2 |
| 23 | GIQ0201 | 1,455 | 561.7 | 1,455 | 456.2 |
| 24 | GIQ0235 | 10,131 | 561.7 | 10,131 | 456.2 |
| 25 | GIQ0228 | 2,798 | 561.7 | 2,798 | 456.2 |
| 26 | GIQ0239 | 4,407 | 561.7 | 4,407 | 456.2 |
| 27 | GIQ0238 | 1,050 | 561.7 | 1,050 | 456.2 |
| 28 | GIQ0174 | 10,890 | 561.7 | 10,890 | 456.2 |
| 29 | GIQ0187 | 5,941 | 561.7 | 5,941 | 456.2 |
| 30 | GIQ0188 | 3,014 | 561.7 | 3,014 | 456.2 |
| 31 | GIQ0189 | 4,038 | 561.7 | 4,038 | 456.2 |
| 32 | GIQ0193 | 4,218 | 561.7 | 4,218 | 456.2 |
| 33 | GIQ0218A, GIQ0218B | 6,225 | 561.7 | 6,225 | 456.2 |
| 34 | GIQ0221A, GIQ0221B, GIQ0221C | 16,319 | 561.7 | 16,319 | 456.2 |
| 35 | GIQ0240 | 37,676 | 561.7 | 37,676 | 456.2 |
| 36 | GIQ0225 | 5,086 | 561.7 | 4,784 | 456.2 |
| 37 | GIQ0226 | 3,326 | 561.7 | 2,949 | 456.2 |
| 38 | GIQ0242 | 599 | 561.7 | 599 | 456.2 |
| 39 | GIQ0171 | 2,004 | 561.7 | 2,004 | 456.2 |
| 40 | GIQ0230 | 4,253 | 561.7 | 4,253 | 456.2 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/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** | | | | |
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| 21 | **Generation Studies** | | | | |
| 22 | GIQ0208 | 252 | 561.7 | 252 | 456.2 |
| 23 | GIQ0241 | 1,219 | 561.7 | 1,219 | 456.2 |
| 24 | GIQ0234 | 918 | 561.7 | 918 | 456.2 |
| 25 | GIQ0217 | 217 | 561.7 | 217 | 456.2 |
| 26 | GIQ0198 | 280 | 561.7 | 280 | 456.2 |
| 27 | GIQ0199 | 3,078 | 561.7 | 3,078 | 456.2 |
| 28 | GIQ0200 | 280 | 561.7 | 280 | 456.2 |
| 29 | GIQ0201 | 294 | 561.7 | 294 | 456.2 |
| 30 | GIQ0236 | 2,442 | 561.7 | 2,442 | 456.2 |
| 31 | GIQ0243 | 1,256 | 561.7 | 1,256 | 456.2 |
| 32 | GIQ0244 | 809 | 561.7 | 809 | 456.2 |
| 33 | GIQ0245 | 704 | 561.7 | 704 | 456.2 |
| 34 | GIQ0248 | 495 | 561.7 | 495 | 456.2 |
| 35 | GIQ0246 | 450 | 561.7 | 450 | 456.2 |
| 36 | GIQ0247 | 1,262 | 561.7 | 1,262 | 456.2 |
| 37 | GIQ0249 | 683 | 561.7 | 683 | 456.2 |
| 38 | GIQ0228 | 662 | 561.7 | 662 | 456.2 |
| 39 | GIQ0250 | 821 | 561.7 | 821 | 456.2 |
| 40 | GIQ0209 | 124 | 561.7 | 124 | 456.2 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/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** | | | | |
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| 20 | | | | | |
| 21 | **Generation Studies** | | | | |
| 22 | GIQ0251 | 430 | 561.7 | 430 | 456.2 |
| 23 | GIQ0252 | 923 | 561.7 | 923 | 456.2 |
| 24 | GIQ0253 | 233 | 561.7 | 233 | 456.2 |
| 25 | GIQ0191 | 233 | 561.7 | 233 | 456.2 |
| 26 | Customer Studies Accruals | ( 4,025) | 561.7 | ( 4,025) | 456.2 |
| 27 | GIQ0122 | 456 | 561.7 | | |
| 28 | GIQ0125 | 4,733 | 561.7 | | |
| 29 | GIQ0122 | 327 | 561.7 | | |
| 30 | GIQ0179 | 3,097 | 561.7 | | |
| 31 | GIQ0180 | 1,823 | 561.7 | | |
| 32 | GIQ0181 | 1,803 | 561.7 | | |
| 33 | GIQ0182 | 1,618 | 561.7 | | |
| 34 | GIQ0183 | 2,245 | 561.7 | | |
| 35 | GIQ0184 | 2,137 | 561.7 | | |
| 36 | GIQ0185 | 1,915 | 561.7 | | |
| 37 | GIQ0186 | 1,649 | 561.7 | | |
| 38 | GIQ0232 | 413 | 561.7 | | |
| 39 | GIQ0203 | 1,334 | 561.7 | | |
| 40 | GIQ0184 | 792 | 561.7 | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/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** | | | | |
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| 21 | **Generation Studies** | | | | |
| 22 | GIQ0185 | 46 | 561.7 | | |
| 23 | GIQ0186 | 46 | 561.7 | | |
| 24 | GIQ0125 | 19,409 | 107 | | |
| 25 | GIQ0122 | 4,558 | 107 | | |
| 26 | GIQ0126 | 12,222 | 107 | | |
| 27 | GIQ0123 | 7,368 | 107 | | |
| 28 | GIQ0124 | 3,666 | 107 | | |
| 29 | GIQ0203 | 55,164 | 107 | | |
| 30 | GIQ0207 | 1,518 | 107 | | |
| 31 | GIQ0179 | 10,960 | 107 | | |
| 32 | GIQ0180 | 9,026 | 107 | | |
| 33 | GIQ0181 | 2,095 | 107 | | |
| 34 | GIQ0182 | 6,098 | 107 | | |
| 35 | GIQ0183 | 6,386 | 107 | | |
| 36 | GIQ0222 | 3,363 | 107 | | |
| 37 | GIQ0223 | 8,817 | 107 | | |
| 38 | GIQ0224 | 22,012 | 107 | | |
| 39 | GIQ0184 | 8,880 | 107 | | |
| 40 | GIQ0185 | 6,906 | 107 | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/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** | | | | |
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| 21 | **Generation Studies** | | | | |
| 22 | GIQ0186 | 3,957 | 107 | | |
| 23 | GIQ0232 | 62 | 107 | | |
| 24 | GIQ0233 | 15,866 | 107 | | |
| 25 | GIQ237A, GIQ237B, GIQ237C | 9,048 | 107 | | |
| 26 | GIQ0224 | 345 | 107 | | |
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***Schedule Page: 231 Line No.: 2 Column: a***

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

***Schedule Page: 231 Line No.: 9 Column: a***

Aref 417112, 417114, 417116, 417118

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

Aref 484637, 484639, 484641, 484643, 484645, 484647, 484649, 484651, 484653, 484655, 484657, 484659, 484661

***Schedule Page: 231 Line No.: 19 Column: a***

Aref 504111, 504113, 504115, 50117, 504121, 504123, 504125, 504127, 504129, 504131, 504133, 504135, 504137, 504139

***Schedule Page: 231.1 Line No.: 10 Column: a***

Aref 464709, 465219, 465221, 465224, 465226

***Schedule Page: 231.1 Line No.: 27 Column: a***

GIQ0102, GIQ0103, GIQ0104, GIQ0105, GIQ0106

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(Next Page is 232)

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## 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 | Balance at Beginning of Current Quarter/Year | Debits | CREDITS | | Balance at end of Current Quarter/Year |
|---|---|---|---|---|---|---|
| | | | | Written off During the Quarter/Year Account Charged | Written off During the Period Amount | |
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | California DSM Regulatory Asset | ( 248,987) | 326,217 | 908 | 1,078,585 | -1,001,355 |
| 2 | Idaho DSM Regulatory Asset | 4,251,758 | 4,814,838 | 908 | 5,374,862 | 3,691,734 |
| 3 | Utah DSM Regulatory Asset | ( 400,156) | 34,682,831 | 431,908 | 26,660,514 | 7,622,161 |
| 4 | Washington DSM Regulatory Asset | ( 1,095,675) | 6,061,769 | 431,908 | 5,030,709 | -64,615 |
| 5 | Wyoming DSM Regulatory Asset (10) | 282,627 | 89,699 | 908 | 62,260 | 310,066 |
| 6 | DSM Regulatory Assets- Accruals | 3,685,456 | 1,779,440 | | | 5,464,896 |
| 7 | Calif. Alternative Rate For Energy (CARE) | 1,742,225 | 897,949 | | | 2,640,174 |
| 8 | Transition Plan - OR (10) | 10,054,172 | | 930.2 | 3,892,300 | 6,161,872 |
| 9 | 2006 Transition Plan - WA (3) | 1,623,722 | | 920 | 668,151 | 955,571 |
| 10 | 2006 Transition Plan - ID (3) | 1,830,583 | | 920 | 610,194 | 1,220,389 |
| 11 | 2006 Transition Severance Costs - WY (3) | | 4,780,000 | 920 | 2,124,444 | 2,655,556 |
| 12 | FAS 109 Deferred Income Taxes Electric | 458,545,491 | | 282 | 18,803,706 | 439,741,785 |
| 13 | SB 1149 Implementation Costs OR Retail Access (5) | 4,493,680 | 90,898 | 407.3 | 4,584,576 | 2 |
| 14 | IDAI Costs No. CA Direct Access (5) | 305,346 | | 407.3 | 305,346 | |
| 15 | Sch 781 Direct Access Shopping Incentive | 520,471 | 412,477 | 407.3 | 933,793 | -845 |
| 16 | Glenrock Mine Excluding Reclamation UT (9) | 2,428,823 | | 930.2 | 1,302,399 | 1,126,424 |
| 17 | Deferred Excess Net Power Costs - OR UE116 | 149,807 | 11,824 | | | 161,631 |
| 18 | Deferred Excess Net Power Costs - WY (1) | 880,619 | 8,393 | 555 | 889,012 | |
| 19 | Deferred Excess Net Power Costs - CA | 758,296 | 27,092 | 555 | 1,260,795 | -475,407 |
| 20 | Deferred Excess NPC - WY 2007 (1) | 29,108,115 | 4,491,382 | 555 | 24,964,142 | 8,635,355 |
| 21 | Deferred Excess Net Power Costs - WY 08 | | 24,231,911 | | | 24,231,911 |
| 22 | OR SB 408 Recovery (1) | 213,053 | | | 213,053 | |
| 23 | Environmental Costs (10) | 7,055,544 | 1,172,340 | 925 | 1,193,011 | 7,034,873 |
| 24 | Environmental Costs - WA (10) | ( 453,691) | 75,498 | 925 | 169,907 | -548,100 |
| 25 | Reg Asset - Environmental Costs | 1,561,958 | 2,915,356 | | | 4,477,314 |
| 26 | Cholla Plant Transaction Costs (26) | 10,756,572 | | 557 | 1,122,424 | 9,634,148 |
| 27 | Cholla Plant Transaction Costs - OR (26) | ( 515,709) | 53,813 | | | -461,896 |
| 28 | Cholla Plant Transaction Costs - WA (26) | ( 929,643) | 97,006 | | | -832,637 |
| 29 | Cholla Plant Transaction Costs - ID (26) | ( 315,995) | 32,974 | | | -283,021 |
| 30 | Washington Colstrip #3 (22) | 682,823 | | 456 | 52,188 | 630,635 |
| 31 | FAS 133 Derivative Net Regulatory Asset | 256,023,770 | 186,118,359 | | | 442,142,129 |
| 32 | Asset Retirement Obligations Regulatory Difference | 52,853,403 | 14,674,732 | 230 | 10,245,517 | 57,282,618 |
| 33 | FAS 158 Pension/Other Post Ret./SERP | 226,252,933 | 366,256,821 | | 28,650,426 | 563,859,328 |
| 34 | RTO Grid West N/R Reg Asset | 1,131,721 | | 182.3 | 1,078,549 | 53,172 |
| 35 | Contra Reg Asset - RTO Grid West | ( 1,131,721) | 1,078,549 | | | -53,172 |
| 36 | RTO Grid West N/R - OR | 878,879 | 74,460 | | | 953,339 |
| 37 | RTO Grid West N/R - WY (3) | 414,098 | | 904 | 184,043 | 230,055 |
| 38 | RTO Grid West N/R - ID (5) | 108,649 | | 904 | 27,163 | 81,486 |
| 39 | Deferred UT Independent Evaluator Fee | 300,511 | 760,239 | 235 | 1,154,000 | -93,250 |
| 40 | Deferred Intervenor Funding Grants - ID | 28,865 | 35,160 | 928 | 28,865 | 35,160 |
| 41 | Deferred Intervenor Funding Grants - OR | 564,108 | 178,739 | 928 | 1,009,743 | -266,896 |
| 42 | Deferred Intervenor - CA (1) | | 251,206 | 928 | 70,777 | 180,429 |
| 43 | Deferred Ind Evaluator Fee - OR | | 1,236,615 | | | 1,236,615 |
| 44 | TOTAL | 1,081,739,789 | 704,214,401 | | 159,600,460 | 1,626,353,730 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $50,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

| Line No. | Description and Purpose of Other Regulatory Assets (a) | Balance at Beginning of Current Quarter/Year (b) | Debits (c) | CREDITS Written off During the Quarter/Year Account Charged (d) | CREDITS Written off During the Period Amount (e) | Balance at end of Current Quarter/Year (f) |
|---|---|---|---|---|---|---|
| 1 | BPA Washington Balancing Account | 1,942,285 | | 440,442 | 624,617 | 1,317,668 |
| 2 | BPA Oregon Balancing Account | 292,678 | | 440,442 | 292,678 | |
| 3 | BPA Idaho Balancing Account | 1,335,440 | 590,578 | | | 1,926,018 |
| 4 | OR Renewable Adjustment Clause | 1,633,653 | 11,328,604 | | | 12,962,257 |
| 5 | Reg Asset - Lake Side Damages | | 1,051,000 | | | 1,051,000 |
| 6 | SB 408 Regulatory Asset - OR (1) | | 27,000,000 | 142 | 14,217,240 | 12,782,760 |
| 7 | SB 408 Regulatory Asset - MCBIT | | 169,882 | 241 | 191,925 | -22,043 |
| 8 | Deferred Ex NPC - WA Hydro (3) | | 6,355,750 | 555 | 338,306 | 6,017,444 |
| 9 | Regulatory Assets - Reclass | 2,139,232 | | 254 | 190,240 | 1,948,992 |
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| 42 | | | | | | |
| 43 | | | | | | |
| 44 | TOTAL | 1,081,739,789 | 704,214,401 | | 159,600,460 | 1,626,353,730 |

FOOTNOTE DATA

***Schedule Page: 232 Line No.: 22 Column: d***

Account 440
Account 442
Account 444

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

Pensions and benefits are charged to functional accounts, which is consistent with where labor is charged.

***Schedule Page: 232.1 Line No.: 9 Column: f***

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

| | YTD December 31, 2008 |
|---|---|
| Reclassified from Regulatory Assets to Regulatory Liabilities: | |
| California DSM Regulatory Asset | $ 1,001,355 |
| Washington DSM Regulatory Asset | 64,615 |
| Sch 781 Direct Access Shopping Incentive | 845 |
| Deferred Excess Net Power Costs – CA | 475,407 |
| Deferred UT Independent Evaulator Fee | 93,250 |
| Deferred Intervenor Funding Grants - OR | 266,896 |
| SB 408 Regulatory Asset - MCBIT | 22,043 |
| | |
| Reclassified from Regulatory Liabilities to Regulatory Assets: | |
| Washington Low Income Program | 24,581 |
| | $ 1,948,992 |

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| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $50,000, whichever is less) may be grouped by classes.

| Line No. | Description of Miscellaneous Deferred Debits<br>(a) | Balance at Beginning of Year<br>(b) | Debits<br>(c) | CREDITS Account Charged<br>(d) | CREDITS Amount<br>(e) | Balance at End of Year<br>(f) |
|---|---|---|---|---|---|---|
| 1 | Joseph Settlement (20) | 1,385,256 | | 557 | 137,380 | 1,247,876 |
| 2 | | | | | | |
| 3 | Lacomb Irrigation (24) | 643,890 | | 557 | 45,720 | 598,170 |
| 4 | | | | | | |
| 5 | Bogus Creek (42) | 1,324,400 | | 557 | 41,280 | 1,283,120 |
| 6 | | | | | | |
| 7 | Mead Phoenix Availability | | | | | |
| 8 | & Trans Charge (50) | 14,890,040 | | 565 | 377,760 | 14,512,280 |
| 9 | | | | | | |
| 10 | TGS Buyout (23) | 186,972 | | 557 | 15,474 | 171,498 |
| 11 | | | | | | |
| 12 | Hermiston Swap (40) | 4,907,564 | | 557 | 171,693 | 4,735,871 |
| 13 | | | | | | |
| 14 | Deferred Longwall Costs | 572,639 | 3,444,414 | 151 | 2,838,668 | 1,178,385 |
| 15 | | | | | | |
| 16 | Point to Point Transmission | 898,257 | 917,762 | 142 | 660,256 | 1,155,763 |
| 17 | | | | | | |
| 18 | Deferred Coal Costs - Wyodak | | | | | |
| 19 | Settlement (22) | 5,027,727 | | 151 | 335,182 | 4,692,545 |
| 20 | | | | | | |
| 21 | Deferred Coal Costs - Arch | | | | | |
| 22 | Settlement (3) | | 7,062,982 | 151 | 2,762,514 | 4,300,468 |
| 23 | | | | | | |
| 24 | Deferred Colstrip Plant Costs | | 118,061 | | | 118,061 |
| 25 | | | | | | |
| 26 | Jim Boyd Hydro Buyout (11) | 504,065 | | 557 | 82,860 | 421,205 |
| 27 | | | | | | |
| 28 | Credit Agmt Costs (5) | 2,399,946 | | 431 | 478,448 | 1,921,498 |
| 29 | | | | | | |
| 30 | PCRB LOC/SBBPA Costs (5) | 1,137,801 | | 427 | 461,747 | 676,054 |
| 31 | | | | | | |
| 32 | PCRB Mode Conversion Costs (10) | 518,044 | | 427 | 128,040 | 390,004 |
| 33 | | | | | | |
| 34 | '94 Series Restruct. Costs (16) | | 751,985 | 427 | 5,961 | 746,024 |
| 35 | | | | | | |
| 36 | Emission Reduction Credits | 406,980 | | | | 406,980 |
| 37 | | | | | | |
| 38 | LGIA LT Transmission Prepaid | 12,303,504 | 2,071,198 | | 4,831,728 | 9,542,974 |
| 39 | | | | | | |
| 40 | Lease Incentives (11) | 1,338,231 | 232,385 | 454.1 | 145,149 | 1,425,467 |
| 41 | | | | | | |
| 42 | LT Lease Comm Prepaid (10) | 921,200 | | 931 | 88,399 | 832,801 |
| 43 | | | | | | |
| 44 | BPA LT Transm Prepaid | 2,400,000 | 7,488,000 | | | 9,888,000 |
| 45 | | | | | | |
| 46 | RTO Grid West N/R- WA (5) | 164,293 | | 904 | 46,941 | 117,352 |
| 47 | Misc. Work in Progress | | | | | |
| 48 | Deferred Regulatory Comm. Expenses (See pages 350 - 351) | | | | | |
| 49 | TOTAL | 52,116,892 | | | | 72,806,094 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $50,000, whichever is less) may be grouped by classes.

| Line No. | Description of Miscellaneous Deferred Debits (a) | Balance at Beginning of Year (b) | Debits (c) | CREDITS Account Charged (d) | CREDITS Amount (e) | Balance at End of Year (f) |
|---|---|---|---|---|---|---|
| 1 | | | | | | |
| 2 | Lake Side Maint. Prepayment | | 6,913,029 | 107 | 835,498 | 6,077,531 |
| 3 | | | | | | |
| 4 | Prepaid Outage Maintenance | | 15,794,545 | 107 | 9,519,953 | 6,274,592 |
| 5 | | | | | | |
| 6 | Other Deferred Debits with | | | | | |
| 7 | balances less than $50,000 | 186,083 | | various | 94,508 | 91,575 |
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| 42 | | | | | | |
| 43 | | | | | | |
| 44 | | | | | | |
| 45 | | | | | | |
| 46 | | | | | | |
| 47 | Misc. Work in Progress | | | | | |
| 48 | Deferred Regulatory Comm. Expenses (See pages 350 - 351) | | | | | |
| 49 | TOTAL | 52,116,892 | | | | 72,806,094 |

***Schedule Page: 233 Line No.: 38 Column: d***

Account 107
Account 165
Account 232
Account 419

## ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

| Line No. | Description and Location (a) | Balance of Begining of Year (b) | Balance at End of Year (c) |
|---|---|---|---|
| 1 | Electric | | |
| 2 | Employee Benefits | 139,413,272 | 246,078,312 |
| 3 | FAS 133 Derivatives | 106,959,021 | 168,654,420 |
| 4 | Regulatory Liability | 43,693,148 | 41,530,110 |
| 5 | | | |
| 6 | | | |
| 7 | Other | 142,263,119 | 130,677,283 |
| 8 | TOTAL Electric (Enter Total of lines 2 thru 7) | 432,328,560 | 586,940,125 |
| 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) | 432,328,560 | 586,940,125 |

Notes

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## CAPITAL STOCKS (Account 201 and 204)

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

| Line No. | Class and Series of Stock and Name of Stock Series<br>(a) | Number of shares Authorized by Charter<br>(b) | Par or Stated Value per share<br>(c) | Call Price at End of Year<br>(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 | | | | |
| 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 | | | | |
| 40 | | | | |
| 41 | | | | |
| 42 | | | | |

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

This class of stock is not redeemable.

***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, 2008, 30,000,000 shares authorized; 30,000,000 available.

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(Next Page is 253)

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

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

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

| Line No. | Item (a) | Amount (b) |
|---|---|---|
| 1 | 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 | 864,950,000 |
| 7 | Gain on sale of ScottishPower stock | 136,208 |
| 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 | | |
| 12 | | |
| 13 | | |
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| 16 | | |
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| 39 | | |
| 40 | TOTAL | 877,063,956 |

***Schedule Page: 253 Line No.: 3 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.: 4 Column: b***

Represents the income tax deduction attributable to the exercise of stock options granted by Scottish Power plc. 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, Inc. 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 indirect parent MidAmerican Energy Holdings Company ("MEHC"), of which $450,000,000 were made during the year ended December 31, 2008.

***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 MEHC in March 2006, subsequent to the sale of PacifiCorp to MEHC. Intermountain Geothermal Company was merged with and into its direct parent, PacifiCorp, on August 31, 2007, with PacifiCorp surviving.

***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 | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## CAPITAL STOCK EXPENSE (Account 214)

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

| Line No. | Class and Series of Stock (a) | Balance at End of Year (b) |
|---|---|---|
| 1 | Common 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 | | |
| 9 | | |
| 10 | | |
| 11 | | |
| 12 | | |
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| 14 | | |
| 15 | | |
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| 20 | | |
| 21 | | |
| 22 | TOTAL | 41,288,207 |

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**(Next Page is 256)**

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

| Line No. | Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a) | Principal Amount Of Debt issued (b) | Total expense, Premium or Discount (c) |
|---|---|---|---|
| 1 | 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 | 5.650% Series due July 15, 2018 | 500,000,000 | 3,007,359 |
| 21 | | | 905,000 D |
| 22 | 7.700% Series due November 15, 2031 | 300,000,000 | 2,874,150 |
| 23 | | | 864,000 D |
| 24 | 5.900% Series due August 15, 2034 | 200,000,000 | 1,892,365 |
| 25 | | | 722,000 D |
| 26 | 5.25% Series due June 15, 2035 | 300,000,000 | 2,912,055 |
| 27 | | | 1,080,000 D |
| 28 | 6.10% Series due August 1, 2036 | 350,000,000 | 2,908,372 |
| 29 | | | 1,141,000 D |
| 30 | 5.75% Series due April 1, 2037 | 600,000,000 | 589,216 |
| 31 | | | 24,000 D |
| 32 | | | |
| 33 | TOTAL | 6,032,262,000 | 63,060,499 |

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

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

| Nominal Date of Issue (d) | Date of Maturity (e) | AMORTIZATION PERIOD Date From (f) | AMORTIZATION PERIOD Date To (g) | Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h) | Interest for Year Amount (i) | Line No. |
|---|---|---|---|---|---|---|
| | | | | | | 1 |
| | | | | | | 2 |
| | | | | | | 3 |
| 09/15/2003 | 09/15/2008 | 09/15/2003 | 09/15/2008 | | 6,091,667 | 4 |
| | | | | | | 5 |
| 04/15/1992 | 10/01/2010 | 04/15/1992 | 10/01/2010 | 9,145,000 | 1,007,925 | 6 |
| 04/15/1992 | 10/01/2011 | 04/15/1992 | 10/01/2011 | 1,144,000 | 110,715 | 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 | 6,640,000 | 649,799 | 10 |
| 04/15/1992 | 10/01/2013 | 04/15/1992 | 10/01/2013 | 6,535,000 | 641,323 | 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 | 12,905,000 | 1,231,079 | 16 |
| 04/15/1992 | 10/01/2015 | 04/15/1992 | 10/01/2015 | 23,308,000 | 2,081,773 | 17 |
| 04/15/1992 | 10/01/2016 | 04/15/1992 | 10/01/2016 | 10,290,000 | 944,820 | 18 |
| 04/15/1992 | 10/01/2017 | 04/15/1992 | 10/01/2017 | 11,460,000 | 1,023,261 | 19 |
| 07/17/2008 | 07/15/2018 | 07/17/2008 | 07/15/2018 | 500,000,000 | 12,869,444 | 20 |
| | | | | | | 21 |
| 11/15/2001 | 11/15/2031 | 11/15/2001 | 11/15/2031 | 300,000,000 | 23,100,000 | 22 |
| | | | | | | 23 |
| 08/24/2004 | 08/15/2034 | 08/24/2004 | 08/15/2034 | 200,000,000 | 11,800,000 | 24 |
| | | | | | | 25 |
| 06/13/2005 | 06/15/2035 | 06/13/2005 | 06/15/2035 | 300,000,000 | 15,750,000 | 26 |
| | | | | | | 27 |
| 08/10/2006 | 08/01/2036 | 08/10/2006 | 08/01/2036 | 350,000,000 | 21,350,000 | 28 |
| | | | | | | 29 |
| 03/14/2007 | 04/01/2037 | 03/14/2007 | 04/01/2037 | 600,000,000 | 34,500,000 | 30 |
| | | | | | | 31 |
| | | | | | | 32 |
| | | | | 5,510,797,000 | 316,049,363 | 33 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

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

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

| Line No. | Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a) | Principal Amount Of Debt issued (b) | Total expense, Premium or Discount (c) |
|---|---|---|---|
| 1 | 6.25% Series due October 15, 2037 | 600,000,000 | 5,127,281 |
| 2 | | | 750,000 D |
| 3 | 6.35% Series due July 15, 2038 | 300,000,000 | 2,254,415 |
| 4 | | | 1,671,000 D |
| 5 | 6.375% Series H Medium-Term Notes due May 15, 2008 | 200,000,000 | 1,416,179 |
| 6 | | | 644,000 D |
| 7 | 7.00% Series H Medium-Term Notes due Jul. 15, 2009 | 125,000,000 | 1,976,904 |
| 8 | | | 451,250 D |
| 9 | 9.15% Series C Medium-Term Notes due Aug. 9, 2011 | 8,000,000 | 75,327 |
| 10 | 8.95% Series C Medium-Term Notes due Sept. 1, 2011 | 25,000,000 | 175,398 |
| 11 | 8.95% Series C Medium-Term Notes due Sept. 1, 2011 | 20,000,000 | 132,118 |
| 12 | 8.92% Series C Medium-Term Notes due Sept. 1, 2011 | 20,000,000 | 188,318 |
| 13 | 8.29% Series C Medium-Term Notes due Dec. 30, 2011 | 3,000,000 | 23,040 |
| 14 | 8.26% Series C Medium-Term Notes due Jan. 10, 2012 | 1,000,000 | 7,649 |
| 15 | 8.28% Series C Medium-Term Notes due Jan. 10, 2012 | 2,000,000 | 13,297 |
| 16 | 8.25% Series C Medium-Term Notes due Feb. 1, 2012 | 3,000,000 | 22,946 |
| 17 | 8.13% Series E Medium-Term Notes due Jan. 22, 2013 | 10,000,000 | 75,827 |
| 18 | 8.53% Series C Medium-Term Notes due Dec. 16, 2021 | 15,000,000 | 115,202 |
| 19 | 8.375% Series C Medium-Term Notes due Dec. 31, 2021 | 5,000,000 | 38,400 |
| 20 | 8.26% Series C Medium-Term Notes due Jan. 7, 2022 | 5,000,000 | 33,243 |
| 21 | 8.27% Series C Medium-Term Notes due Jan. 10, 2022 | 4,000,000 | 30,594 |
| 22 | 8.05% Series E Medium-Term Notes due Sept. 1, 2022 | 15,000,000 | 131,471 |
| 23 | 8.07% Series E Medium-Term Notes due Sept. 9, 2022 | 8,000,000 | 70,118 |
| 24 | 8.12% Series E Medium-Term Notes due Sept. 9, 2022 | 50,000,000 | 438,238 |
| 25 | 8.11% Series E Medium-Term Notes due Sept. 9, 2022 | 12,000,000 | 105,177 |
| 26 | 8.05% Series E Medium-Term Notes due Sept. 14, 2022 | 10,000,000 | 87,648 |
| 27 | 8.08% Series E Medium-Term Notes due Oct. 14, 2022 | 26,000,000 | 208,198 |
| 28 | 8.08% Series E Medium-Term Notes due Oct. 14, 2022 | 25,000,000 | 200,190 |
| 29 | 8.23% Series E Medium-Term Notes due Jan. 20, 2023 | 5,000,000 | 37,914 |
| 30 | 8.23% Series E Medium-Term Notes due Jan. 20, 2023 | 4,000,000 | 30,331 |
| 31 | | | -81,560 P |
| 32 | 7.26% Series F Medium-Term Notes due July 21, 2023 | 27,000,000 | 246,981 |
| 33 | TOTAL | 6,032,262,000 | 63,060,499 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

| Nominal Date of Issue (d) | Date of Maturity (e) | AMORTIZATION PERIOD Date From (f) | AMORTIZATION PERIOD Date To (g) | Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h) | Interest for Year Amount (i) | Line No. |
|---|---|---|---|---|---|---|
| 10/03/2007 | 10/15/2037 | 10/03/2007 | 10/15/2037 | 600,000,000 | 37,500,000 | 1 |
| | | | | | | 2 |
| 07/17/2008 | 07/15/2038 | 07/17/2008 | 07/15/2038 | 300,000,000 | 8,678,333 | 3 |
| | | | | | | 4 |
| 05/12/1998 | 05/15/2008 | 05/12/1998 | 05/15/2008 | | 4,781,250 | 5 |
| | | | | | | 6 |
| 07/15/1997 | 07/15/2009 | 07/15/1997 | 07/15/2009 | 125,000,000 | 8,750,000 | 7 |
| | | | | | | 8 |
| 08/09/1991 | 08/09/2011 | 08/09/1991 | 08/09/2011 | 8,000,000 | 732,000 | 9 |
| 08/16/1991 | 09/01/2011 | 08/16/1991 | 09/01/2011 | 25,000,000 | 2,237,500 | 10 |
| 08/16/1991 | 09/01/2011 | 08/16/1991 | 09/01/2011 | 20,000,000 | 1,790,000 | 11 |
| 08/16/1991 | 09/01/2011 | 08/16/1991 | 09/01/2011 | 20,000,000 | 1,784,000 | 12 |
| 12/31/1991 | 12/30/2011 | 12/31/1991 | 12/30/2011 | 3,000,000 | 248,700 | 13 |
| 01/09/1992 | 01/10/2012 | 01/09/1992 | 01/10/2012 | 1,000,000 | 82,600 | 14 |
| 01/10/1992 | 01/10/2012 | 01/10/1992 | 01/10/2012 | 2,000,000 | 165,600 | 15 |
| 01/15/1992 | 02/01/2012 | 01/15/1992 | 02/01/2012 | 3,000,000 | 247,500 | 16 |
| 01/20/1993 | 01/22/2013 | 01/20/1993 | 01/22/2013 | 10,000,000 | 813,000 | 17 |
| 12/16/1991 | 12/16/2021 | 12/16/1991 | 12/16/2021 | 15,000,000 | 1,279,500 | 18 |
| 12/31/1991 | 12/31/2021 | 12/31/1991 | 12/31/2021 | 5,000,000 | 418,750 | 19 |
| 01/08/1992 | 01/07/2022 | 01/08/1992 | 01/07/2022 | 5,000,000 | 413,000 | 20 |
| 01/09/1992 | 01/10/2022 | 01/09/1992 | 01/10/2022 | 4,000,000 | 330,800 | 21 |
| 09/18/1992 | 09/01/2022 | 09/18/1992 | 09/01/2022 | 15,000,000 | 1,207,500 | 22 |
| 09/09/1992 | 09/09/2022 | 09/09/1992 | 09/09/2022 | 8,000,000 | 645,600 | 23 |
| 09/11/1992 | 09/09/2022 | 09/11/1992 | 09/09/2022 | 50,000,000 | 4,060,000 | 24 |
| 09/11/1992 | 09/09/2022 | 09/11/1992 | 09/09/2022 | 12,000,000 | 973,200 | 25 |
| 09/14/1992 | 09/14/2022 | 09/14/1992 | 09/14/2022 | 10,000,000 | 805,000 | 26 |
| 10/15/1992 | 10/14/2022 | 10/15/1992 | 10/14/2022 | 26,000,000 | 2,100,800 | 27 |
| 10/15/1992 | 10/14/2022 | 10/15/1992 | 10/14/2022 | 25,000,000 | 2,020,000 | 28 |
| 01/20/1993 | 01/20/2023 | 01/20/1993 | 01/20/2023 | 5,000,000 | 411,500 | 29 |
| 01/29/1993 | 01/20/2023 | 01/29/1993 | 01/20/2023 | 4,000,000 | 329,200 | 30 |
| | | | | | | 31 |
| 07/22/1993 | 07/21/2023 | 07/22/1993 | 07/21/2023 | 27,000,000 | 1,960,200 | 32 |
| | | | | 5,510,797,000 | 316,049,363 | 33 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

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

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

| Line No. | Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a) | Principal Amount Of Debt issued (b) | Total expense, Premium or Discount (c) |
|---|---|---|---|
| 1 | 7.26% Series F Medium-Term Notes due July 21, 2023 | 11,000,000 | 100,622 |
| 2 | 7.23% Series F Medium-Term Notes due Aug. 16, 2023 | 15,000,000 | 137,211 |
| 3 | 7.24% Series F Medium-Term Notes due Aug. 16, 2023 | 30,000,000 | 274,423 |
| 4 | 6.75% Series F Medium-Term Notes due Sept. 14, 2023 | 5,000,000 | 38,250 |
| 5 | 6.75% Series F Medium-Term Notes due Sept. 14, 2023 | 2,000,000 | 15,300 |
| 6 | 6.72% Series F Medium-Term Notes due Sept. 14, 2023 | 2,000,000 | 15,300 |
| 7 | 6.75% Series F Medium-Term Notes due Oct. 26, 2023 | 20,000,000 | 152,326 |
| 8 | 6.75% Series F Medium-Term Notes due Oct. 26, 2023 | 16,000,000 | 121,861 |
| 9 | 6.75% Series F Medium-Term Notes due Oct. 26, 2023 | 12,000,000 | 91,396 |
| 10 | 6.71% Series G Medium-Term Notes due Jan. 15, 2026 | 100,000,000 | 904,467 |
| 11 | Subtotal - First Mortgage Bonds | 5,293,892,000 | 48,205,459 |
| 12 | | | |
| 13 | Pollution Control Obligations - Secured by Pledged First Mortgage Bonds: | | |
| 14 | | | |
| 15 | Poll Ctrl Rev Refunding Bonds, Moffat County, CO, Series 1994 | 40,655,000 | 874,159 |
| 16 | 5-5/8% Poll Ctrl Rev Refunding Bonds, Lincoln County, WY, Series 1993 | 8,300,000 | 228,980 |
| 17 | | | 197,125 D |
| 18 | 5.65% Poll Ctrl Rev Refunding Bonds, Emery County, Utah, Series 1993A | 46,500,000 | 1,624,793 |
| 19 | 5-5/8% Poll Ctrl Rev Refunding Bonds, Emery County, Utah, Series 1993B | 16,400,000 | 625,551 |
| 20 | | | 389,500 D |
| 21 | Poll Ctrl Rev Refunding Bonds, Sweetwater County, WY, Series 1994 | 21,260,000 | 510,479 |
| 22 | Poll Ctrl Rev Refunding Bonds, Converse County, WY, Series 1994 | 8,190,000 | 209,777 |
| 23 | Poll Ctrl Rev Refunding Bonds, Emery County, UT, Series 1994 | 121,940,000 | 3,274,246 |
| 24 | Poll Ctrl Rev Refunding Bonds, Carbon County, UT, Series 1994 | 9,365,000 | 206,519 |
| 25 | Poll Ctrl Rev Refunding Bonds, Lincoln County, WY, Series 1994 | 15,060,000 | 422,858 |
| 26 | Poll Ctrl Rev Refunding Bonds, Converse County, WY, Series 1988 | 17,000,000 | 155,970 |
| 27 | Poll Ctrl Revenue Bonds, Sweetwater County, WY, Series 1984 | 15,000,000 | 122,887 |
| 28 | | | 105,000 D |
| 29 | Poll Ctrl Rev Refunding Bonds, Lincoln Cnty, WY, Series 1991 | 45,000,000 | 771,836 |
| 30 | Poll Ctrl Revenue Bonds, City of Forsyth, MT, Series 1986 | 8,500,000 | 304,824 |
| 31 | Environ. Imprvmnt Rev Bonds, Converse County, WY, Series 1995 | 5,300,000 | 132,043 |
| 32 | Environ. Imprvmnt Rev Bonds, Lincoln County, WY, Series 1995 | 22,000,000 | 404,262 |
| 33 | TOTAL | 6,032,262,000 | 63,060,499 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

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

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

| Nominal Date of Issue (d) | Date of Maturity (e) | AMORTIZATION PERIOD Date From (f) | AMORTIZATION PERIOD Date To (g) | Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h) | Interest for Year Amount (i) | Line No. |
|---|---|---|---|---|---|---|
| 07/22/1993 | 07/21/2023 | 07/22/1993 | 07/21/2023 | 11,000,000 | 798,600 | 1 |
| 08/16/1993 | 08/16/2023 | 08/16/1993 | 08/16/2023 | 15,000,000 | 1,084,500 | 2 |
| 08/16/1993 | 08/16/2023 | 08/16/1993 | 08/16/2023 | 30,000,000 | 2,172,000 | 3 |
| 09/14/1993 | 09/14/2023 | 09/14/1993 | 09/14/2023 | 5,000,000 | 337,500 | 4 |
| 09/14/1993 | 09/14/2023 | 09/14/1993 | 09/14/2023 | 2,000,000 | 135,000 | 5 |
| 09/14/1993 | 09/14/2023 | 09/14/1993 | 09/14/2023 | 2,000,000 | 134,400 | 6 |
| 10/26/1993 | 10/26/2023 | 10/26/1993 | 10/26/2023 | 20,000,000 | 1,350,000 | 7 |
| 10/26/1993 | 10/26/2023 | 10/26/1993 | 10/26/2023 | 16,000,000 | 1,080,000 | 8 |
| 10/26/1993 | 10/26/2023 | 10/26/1993 | 10/26/2023 | 12,000,000 | 810,000 | 9 |
| 01/23/1996 | 01/15/2026 | 01/23/1996 | 01/15/2026 | 100,000,000 | 6,710,000 | 10 |
| | | | | 4,772,427,000 | 287,829,339 | 11 |
| | | | | | | 12 |
| | | | | | | 13 |
| | | | | | | 14 |
| 11/17/1994 | 05/01/2013 | 11/17/1994 | 05/01/2013 | 40,655,000 | 1,639,918 | 15 |
| 11/15/1993 | 11/01/2021 | 11/15/1993 | 11/01/2021 | 8,300,000 | 476,835 | 16 |
| | | | | | | 17 |
| 11/15/1993 | 11/01/2023 | 11/15/1993 | 11/01/2023 | 46,500,000 | 2,683,050 | 18 |
| 11/15/1993 | 11/01/2023 | 11/15/1993 | 11/01/2023 | 16,400,000 | 942,180 | 19 |
| | | | | | | 20 |
| 11/17/1994 | 11/01/2024 | 11/17/1994 | 11/01/2024 | 21,260,000 | 975,021 | 21 |
| 11/17/1994 | 11/01/2024 | 11/17/1994 | 11/01/2024 | 8,190,000 | 376,483 | 22 |
| 11/17/1994 | 11/01/2024 | 11/17/1994 | 11/01/2024 | 121,940,000 | 5,489,163 | 23 |
| 11/17/1994 | 11/01/2024 | 11/17/1994 | 11/01/2024 | 9,365,000 | 373,212 | 24 |
| 11/17/1994 | 11/01/2024 | 11/17/1994 | 11/01/2024 | 15,060,000 | 705,107 | 25 |
| 01/01/1988 | 01/01/2014 | 01/01/1988 | 01/01/2014 | 17,000,000 | 680,352 | 26 |
| 12/01/1984 | 12/01/2014 | 12/01/1984 | 12/01/2014 | 15,000,000 | 600,357 | 27 |
| | | | | | | 28 |
| 01/17/1991 | 01/01/2016 | 01/17/1991 | 01/01/2016 | 45,000,000 | 1,640,032 | 29 |
| 12/01/1986 | 12/01/2016 | 12/01/1986 | 12/01/2016 | 8,500,000 | 359,450 | 30 |
| 11/17/1995 | 11/01/2025 | 11/17/1995 | 11/01/2025 | 5,300,000 | 224,251 | 31 |
| 11/17/1995 | 11/01/2025 | 11/17/1995 | 11/01/2025 | 22,000,000 | 952,642 | 32 |
| | | | | 5,510,797,000 | 316,049,363 | 33 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

| Line No. | Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a) | Principal Amount Of Debt issued (b) | Total expense, Premium or Discount (c) |
|---|---|---|---|
| 1 | Subtotal Pollution Control Obligations - Secured by Pledged First Mortgage Bonds | 400,470,000 | 10,560,809 |
| 2 | | | |
| 3 | | | |
| 4 | Pollution Control Obligations - Unsecured | | |
| 5 | | | |
| 6 | Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1992A | 9,335,000 | 167,524 |
| 7 | Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1992B | 6,305,000 | 151,908 |
| 8 | Poll Ctrl Rev Refndng Bonds, Converse County, WY, Series 1992 | 22,485,000 | 242,163 |
| 9 | Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1988B | 11,500,000 | 84,822 |
| 10 | Poll Ctrl Rev Refndng Bonds, Sweetwater County, WY, Ser. 1990A | 70,000,000 | 660,750 |
| 11 | Poll Ctrl Rev Refndng Bonds, Emery County, UT, Series 1991 | 45,000,000 | 872,505 |
| 12 | Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1988A | 50,000,000 | 422,443 |
| 13 | Poll Ctrl Rev Refndng Bonds, City of Forsyth, MT, Series 1988 | 45,000,000 | 380,198 |
| 14 | Poll Ctrl Rev Refndng Bonds, City of Gillette, WY, Ser. 1988 | 41,200,000 | 351,905 |
| 15 | Environ. Imprvmnt Rev Bonds, Sweetwater County, WY, Series 1995 | 24,400,000 | 225,000 |
| 16 | 6.150% Environ. Imprvmnt Rev Bonds, Emery County, UT, Series 1996 | 12,675,000 | 556,549 |
| 17 | | | 178,464 D |
| 18 | | | |
| 19 | Subtotal - Pollution Control Obligations - Unsecured | 337,900,000 | 4,294,231 |
| 20 | | | |
| 21 | | | |
| 22 | | | |
| 23 | TOTAL ACCOUNT 221 | 6,032,262,000 | 63,060,499 |
| 24 | | | |
| 25 | | | |
| 26 | Reacquired Bonds: (Account 222) | | |
| 27 | | | |
| 28 | | | |
| 29 | Advances from Associated Companies: (Account 223) | | |
| 30 | | | |
| 31 | | | |
| 32 | | | |
| 33 | TOTAL | 6,032,262,000 | 63,060,499 |

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

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

| Nominal Date of Issue (d) | Date of Maturity (e) | AMORTIZATION PERIOD Date From (f) | AMORTIZATION PERIOD Date To (g) | Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h) | Interest for Year Amount (i) | Line No. |
|---|---|---|---|---|---|---|
| | | | | 400,470,000 | 18,118,053 | 1 |
| | | | | | | 2 |
| | | | | | | 3 |
| | | | | | | 4 |
| | | | | | | 5 |
| 09/29/1992 | 12/01/2020 | 09/29/1992 | 12/01/2020 | 9,335,000 | 338,272 | 6 |
| 09/29/1992 | 12/01/2020 | 09/29/1992 | 12/01/2020 | 6,305,000 | 227,027 | 7 |
| 09/29/1992 | 12/01/2020 | 09/29/1992 | 12/01/2020 | 22,485,000 | 812,615 | 8 |
| 01/01/1988 | 01/01/2014 | 01/01/1988 | 01/01/2014 | 11,500,000 | 301,085 | 9 |
| 07/25/1990 | 07/01/2015 | 07/25/1990 | 07/01/2015 | 70,000,000 | 1,980,549 | 10 |
| 05/23/1991 | 07/01/2015 | 05/23/1991 | 07/01/2015 | 45,000,000 | 1,290,742 | 11 |
| 01/01/1988 | 01/01/2017 | 01/01/1988 | 01/01/2017 | 50,000,000 | 1,341,954 | 12 |
| 01/01/1988 | 01/01/2018 | 01/01/1988 | 01/01/2018 | 45,000,000 | 1,181,175 | 13 |
| 01/01/1988 | 01/01/2018 | 01/01/1988 | 01/01/2018 | 41,200,000 | 1,206,375 | 14 |
| 12/14/1995 | 11/01/2025 | 12/14/1995 | 11/01/2025 | 24,400,000 | 642,664 | 15 |
| 09/24/1996 | 09/01/2030 | 09/24/1996 | 09/01/2030 | 12,675,000 | 779,513 | 16 |
| | | | | | | 17 |
| | | | | | | 18 |
| | | | | 337,900,000 | 10,101,971 | 19 |
| | | | | | | 20 |
| | | | | | | 21 |
| | | | | | | 22 |
| | | | | 5,510,797,000 | 316,049,363 | 23 |
| | | | | | | 24 |
| | | | | | | 25 |
| | | | | | | 26 |
| | | | | | | 27 |
| | | | | | | 28 |
| | | | | | | 29 |
| | | | | | | 30 |
| | | | | | | 31 |
| | | | | | | 32 |
| | | | | 5,510,797,000 | 316,049,363 | 33 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

| Line No. | Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a) | Principal Amount Of Debt issued (b) | Total expense, Premium or Discount (c) |
|---|---|---|---|
| 1 | Other Long-Term Debt: (Account 224) | | |
| 2 | | | |
| 3 | TOTAL ACCOUNT 224 | | |
| 4 | | | |
| 5 | | | |
| 6 | Long-Term Debt Authorized but Unissued | | |
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| 31 | | | |
| 32 | | | |
| 33 | TOTAL | 6,032,262,000 | 63,060,499 |

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

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

| Nominal Date of Issue (d) | Date of Maturity (e) | AMORTIZATION PERIOD Date From (f) | AMORTIZATION PERIOD Date To (g) | Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h) | Interest for Year Amount (i) | Line No. |
|---|---|---|---|---|---|---|
| | | | | | | 1 |
| | | | | | | 2 |
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| | | | | | | 31 |
| | | | | | | 32 |
| | | | | 5,510,797,000 | 316,049,363 | 33 |

**Schedule Page: 256 Line No.: 1 Column: i**

Total interest expense of $316,049,363 does not include $2,476,375 of interest received while PacifiCorp temporarily held certain pollution control revenue bonds.

For further information regarding long-term debt, refer to Note 9 of Notes to Financial Statements included in this Form No. 1.

**Schedule Page: 256 Line No.: 20 Column: a**

In July 2008, PacifiCorp issued $500 million of its 5.65% First Mortgage Bonds due July 15, 2018. State commission authorizations for this issuance were as follows:

Oregon Public Utility Commission, Docket No. UF-4243, Order No. 08-013, dated January 14, 2008.

Idaho Public Utility Commission, Case No. PAC-E-07-16, Order No. 30489, dated January 22, 2008.

**Schedule Page: 256.1 Line No.: 3 Column: a**

In July 2008, PacifiCorp issued $300 million of its 6.35% First Mortgage Bonds due July 15, 2038. State commission authorizations for this issuance were as follows:

Oregon Public Utility Commission, Docket No. UF-4243, Order No. 08-013, dated January 14, 2008.

Idaho Public Utility Commission, Case No. PAC-E-07-16, Order No. 30489, dated January 22, 2008.

**Schedule Page: 256.3 Line No.: 26 Column: a**

In September 2008, PacifiCorp acquired $216 million of its insured variable-rate tax-exempt bond obligations due to the significant reduction in market liquidity for insured variable-rate obligations. In November 2008, the associated insurance and related standby bond purchase agreements were terminated and these variable-rate long-term debt obligations were remarketed with credit enhancement and liquidity support provided by $220 million of letters of credit issued under PacifiCorp's two unsecured revolving credit facilities.

**Schedule Page: 256.4 Line No.: 6 Column: a**

For authorization for the issuance of long-term debt ($2.0 billion authorized; $1.2 billion available as of December 31, 2008), refer to page 104, *Important Changes During the Year*, Item 6, of this Form No. 1.

Authorization to borrow the proceeds of pollution control revenue refunding bonds issued (total of $300,345,000 authorized and available as of December 31, 2008) by the Counties of Emery, Utah; Carbon, Utah; Converse, Wyoming; Lincoln, Wyoming; Sweetwater, Wyoming; and Moffat, Colorado;

Authorization to borrow the proceeds of new pollution control revenue bonds issued (total of $150,000,000 authorized and available as of December 31, 2008) by one or more of the following counties or municipalities: Emery, Utah; Converse, Wyoming; Lincoln, Wyoming; Sweetwater, Wyoming; City of Gillette, Wyoming; Navajo County, Arizona; and Routt County, Colorado is as follows:

Oregon Public Utility Commission, Docket No. UF-4250, Order No. 08-382, dated July 29, 2008.

Idaho Public Utilities Commission, Case No. PAC-E-08-05, Order No. 30606, dated August 4, 2008.

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(Next Page is 261)

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

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

| Line No. | Particulars (Details) (a) | Amount (b) |
|---|---|---|
| 1 | Net Income for the Year (Page 117) | 458,282,904 |
| 2 | | |
| 3 | | |
| 4 | Taxable Income Not Reported on Books | |
| 5 | | |
| 6 | | |
| 7 | | |
| 8 | Other | 159,877,277 |
| 9 | Deductions Recorded on Books Not Deducted for Return | |
| 10 | | |
| 11 | | |
| 12 | | |
| 13 | Other | 1,101,723,055 |
| 14 | Income Recorded on Books Not Included in Return | |
| 15 | | |
| 16 | | |
| 17 | | |
| 18 | Other | 165,567,283 |
| 19 | Deductions on Return Not Charged Against Book Income | |
| 20 | | |
| 21 | | |
| 22 | | |
| 23 | | |
| 24 | | |
| 25 | Other | 1,599,355,018 |
| 26 | State Tax Deductions | 5,441,058 |
| 27 | Federal Tax Net Income | -39,598,007 |
| 28 | Show Computation of Tax: | |
| 29 | | |
| 30 | Federal Income Tax at 35.00% | -13,859,302 |
| 31 | Provision to Return Adjustment | -27,392,440 |
| 32 | Tax Reserve changes | 2,763,498 |
| 33 | Wind Credits | -24,539,646 |
| 34 | Mining Rescue Training Credit | -50,009 |
| 35 | Research & Experimentation Credits | -540,673 |
| 36 | Current Federal Tax Interest | -69,028 |
| 37 | Deferred Correction/Uncertain Position | 18,610 |
| 38 | | |
| 39 | | |
| 40 | Federal Income Tax Accrual | -63,668,990 |
| 41 | | |
| 42 | | |
| 43 | | |
| 44 | | |

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

| Particulars (Details) | Amounts |
|---|---|
| Contributions in Aid of Construction | 65,247,545 |
| Reimbursements | 2,196,309 |
| Avoided Costs | 61,014,506 |
| Deferred Excess Net Power Costs - CA | 1,233,703 |
| Deferred Excess Net Power Costs - WY | 20,472,760 |
| ID MEHC 2006 Transition Costs | 610,194 |
| 781 Shopping Incentive | 521,316 |
| Reg liability BPA balancing accounts | 1,281,218 |
| Reg Liability - UT Home Energy Lifeline | 252,482 |
| Reg Liability - WA Low Energy Program | 17,383 |
| OR Reg Asset/Liability Consolidation | 470,103 |
| Oregon Gain on Sale | 1,239,225 |
| March 2006 Transition Plan Costs - WA | 668,151 |
| Sec. 263A Inventory Change - PMI | 1,217,884 |
| Accrued Royalties | 696,688 |
| NW Power Act -WA | 624,616 |
| SMUD Revenue Imputation - UT reg liab | 207,540 |
| Equity Earnings in Subsidiaries | 1,905,654 |
| Total | 159,877,277 |

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

| Particulars (Details) | Amounts |
|---|---|
| Fed/State Tax Expense | 238,515,739 |
| % capitalized labor costs for Powertax input | 1,590,858 |
| Meals & Entertainment | 738,260 |
| Penalties | 510,618 |
| Penalties - PMI | 138,682 |
| Lobbying expenses | 1,221,209 |
| Meals & Entertainment - Bridger Coal | 18,198 |
| MEHC Insurance Services - Premium | 6,969,001 |
| Mining Rescue Training Credit Addback | 36,254 |
| PMI Fuel Tax Credit | 15,978 |
| Mining Rescue Training - PMI | 13,755 |
| 30% capitalized labor costs for Powertax input | 6,535,202 |
| Book Depreciation | 485,189,941 |
| Book Depreciation - PMI | 13,190,668 |
| Book Cost Depletion - Addback | 2,157,064 |
| Book Depletion - SRC | 206,936 |
| Book Depletion-Step up basis adjustment | 98,385 |
| May 2000 Transition Plan Costs - OR | 3,892,299 |
| Glenrock Excluding Reclamation - UT | 1,302,399 |
| Reg Asset - FAS 158 Post Ret. Liab. | 15,178,614 |
| Environmental Costs - WA | 94,409 |
| Cholla Plt Transact Costs - APS Amort | 938,633 |
| WA Disallowed Colstrip #3 - Write-off | 52,188 |
| Wyoming PCAM Def Net Power Costs | 880,619 |
| IDAI Costs - direct access | 305,346 |
| SB 1149-Related Regulatory Assets | 448,454 |
| Deferred Intervener Funding Grants | 831,003 |
| RTO Grid West Note Receivable - Allowance | 1,078,549 |

| | |
|---|---|
| RTO Grid West Notes Receivable - WY | 184,044 |
| RTO Grid West Notes Receivable - ID | 27,162 |
| Contra Pension Reg Asset MMT & CTG - OR | 11,821,555 |
| Contra Pension Reg Asset MMT & CTG - WY | 5,311,868 |
| Reg Asset - Pension MMT - UT | 289,308 |
| Contra Pension Reg Asset CTG - UT | 16,886,329 |
| Contra Pension Reg Asset MMT & CTG - CA | 1,022,338 |
| Contra Pension Reg Asset CTG - WA | 3,138,141 |
| Reg Asset - Post - Ret MMT - UT | 284,683 |
| Unrecovered Plant - Powerdale | 4,365,259 |
| Deferred UT Independent Evaluation Fee | 393,761 |
| Reg Asset balance reclass | 190,240 |
| Trojan Decomissioning Costs - Regulatory | 1,464,600 |
| SB 1149 Costs | 4,045,224 |
| Post Merger Loss-Reacq Debt - Addback | 4,223,214 |
| Coal Pile Inventory Adjustment | 2,298,001 |
| Prepaid Insurance - IBEW 157 contingency reserve | 15,184 |
| RTO Grid West Note Receivable - w/o - WA | 46,941 |
| Deferred Coal Cost - Arch | 2,762,514 |
| TGS Buyout | 15,474 |
| Lakeview Buyout | 43,280 |
| Joseph Settlement | 137,381 |
| Hermiston Swap | 171,693 |
| FAS 133 Derivatives - Current | 65,683,730 |
| ARO Reg Liabilities | 97,517 |
| Non-ARO Liabilily - Reg Liability | 25,093,146 |
| Reg Liability - OR Energy Conservation Charge | 775,874 |
| Reg Liability - Blue Sky Program WA | 5,781 |
| Reg Liability - Blue Sky Program CA | 12,660 |
| Reg Liability - Blue Sky Program UT | 332,106 |
| Reg Liability - Blue Sky Program ID | 30,523 |
| Reg Liability - CA Gain on Sale of Asset | 45,034 |
| Reg Liability - UT Gain on Sale of Asset | 1,019,355 |
| Reg Liability - ID Gain on Sale of Asset | 156,434 |
| Reg Liability - WY Gain on Sale of Asset | 352,888 |
| Self Insured Health Benefit | 708,350 |
| Vacation Accrual - Cash Basis (2.5 mos) | 1,893,488 |
| Severance Accrual - Cash Basis | 26,539 |
| FAS 133 Derivatives - noncurrent | 122,738,278 |
| FAS 143 ARO Liability | 5,611,655 |
| Bad Debts Allowance - Cash Basis | 882,108 |
| Bear River Settlement Agreement | 468,675 |
| Rogue River - Habitat Enhancement Liability | 20,017 |
| Lewis River Settlement Agreement | 138,815 |
| Misc Def Dr - Prop Damage Repairs | 34 |
| N. Umpqua Settlement Agreement | 1,165,477 |
| Umpqua Settlement Agreement | 583,489 |
| Reverse Accrued Final Reclamation | 778,291 |
| PMI EITF04-6 Pre-Stripping Costs | 1,300,189 |
| Injuries and Damages Accrual - Cash Basis | 2,377,902 |
| FAS 112 Book Reserve | 502,513 |
| Bridger Coal Company ARO - Liability | 140,894 |
| Coal Mine Developent - PMI | 7,300,703 |

| | |
|---|---|
| FAS 115 Mark to Market Accrual - Bridger - Reclass | 16,914,432 |
| Bridger Coal Company Reclamation Trust Earning - PMI | 3,278,703 |
| Total | 1,101,723,055 |

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

| Particulars (Details) | Amounts |
|---|---|
| MEHC Insurance Services - Receivable | (5,753,058) |
| Medicare Subsidy | (6,340,731) |
| PMI Overriding Coal Royalty % Depletion | (15,307) |
| AFUDC | (74,407,631) |
| Basis Intangible Difference | (6,327,691) |
| Gain/Loss on Prop. Disposition | (34,735,281) |
| Book Gain/Loss on Land Sales | (2,115,225) |
| OR - RCAC Sep-Dec 07 Deferred | (11,328,605) |
| OR SB 408 Recovery | (12,569,707) |
| OR Rate Refunds | (2) |
| Reg Liab - OR Balance Consol | (190,240) |
| West Valley Lease Reduction - CA | (25,986) |
| West Valley Lease Reduction - ID | (218,926) |
| West Valley Lease Reduction - WY | (91,036) |
| West Valley Lease Reduction - UT | (418,170) |
| Def Reg Asset - Transmission Srvc Deposit | (9,624,475) |
| Def Reg Asset - Foote Creek Contract | (137,640) |
| Deferred Regulatory Expense | (6,296) |
| Tenant Lease Allow - PSU Call Cntr | (62,756) |
| Unearned Joint Use Pole Contact Revenue | (55,732) |
| Idaho Customer Balancing Account | (590,578) |
| Bridger Coal Company Gain/Loss on Assets Disposed | (1,843) |
| MCI FOG Wire Lease | (371) |
| Redding Contract - Prepaid | (549,996) |
| Total | (165,567,283) |

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

| Particulars (Details) | Amounts |
|---|---|
| PPL Pre - 1943 Preferred Stock Div - Deduction | (381,063) |
| Utah Deferred Comp / COLI | (1,524,541) |
| Bridger Coal Company Depletion - PMI | (2,340,055) |
| Dividend Received Deduction | (236,840) |
| Tax Depreciation | (1,095,617,890) |
| Depreciation (Tax Depreciation M-1) - PMI | (24,251,279) |
| Capitalized Depreciation | (5,040,868) |
| Coal Mine Development | (907,726) |
| Coal Mine Extension | (1,186,595) |
| Removal Costs | (44,626,151) |
| Cholla SHL-NOPA (Lease Amortization) | (55,967) |
| ARO - reclass to ARO liabilies | (2,580,122) |
| ARO - reclass to reg assets/liability & ARO liability | (25,093,146) |
| Tax Percentage Depletion - Deduction | (7,970,319) |
| DTA 105.154 Section 383 capital loss carryforward | (230,245) |
| Tax Depletion | (191,818) |
| Fixed Asset - Book/Tax | (37,806) |
| ARO Reg Assets | (3,129,050) |
| Reg Asset - FAS 158 Pension Liab Adj. | (33,757,816) |
| Environmental Clean-up Accrual | (2,894,686) |
| Def Reg Asset - OR Def Net Power Costs | (11,824) |

| | |
|---|---|
| CA Deferred Intervenor Funding | (180,429) |
| Reg Asset - Lake Side Liq. | (1,051,000) |
| Contra - RTO Grid West N/R Allowance | (1,078,549) |
| RTO Grid West Notes Receivable - OR | (74,460) |
| Reg Asset - Deferred OR Independent Evaluator Fees | (1,236,614) |
| Deferred Excess Net Power Costs - WY 08 | (24,231,911) |
| Deferred Excess Net Power Costs - WA Hydro | (6,017,444) |
| WY - 2006 Transition Severance Costs | (2,655,556) |
| Weatherization | (9,547,863) |
| Regulatory Asset - Net FAS 133 | (186,118,359) |
| Trapper Mining Stock Basis | (1,392,041) |
| Prepaid Taxes - OR PUC | (124,784) |
| Prepaid Taxes - UT PUC | (197,014) |
| Prepaid Taxes - ID PUC | (57,134) |
| Other Prepaid | (43,034) |
| Prepaid Taxes - Property Taxes | (185,449) |
| WY Joint Water Board Reserve - Deduction | (300,000) |
| Energy trading derivatives - current | (1,258,283) |
| Energy trading derivatives - noncurrent | (983,795) |
| Wasach workers comp reserve | (297,563) |
| CA-California Alternative Rate for Energy Program (CARE) | (897,949) |
| A&G Credit - WA | (428,241) |
| A&G Credit - CA | (41,623) |
| A&G Credit - ID | (225,623) |
| A&G Credit - WY | (34,046) |
| Reg Liability - Blue Sky Program OR | (181,358) |
| Reg Liability - Blue Sky Program WY | (3,486) |
| Reg. Liability - Deferred Benefit - Arch Settlement | (1,960,857) |
| Deferred Compensation Accrual - Cash Basis | (2,125,011) |
| Pension / Retirement Accrual - Cash Basis | (121,895) |
| Accrued CIC Severance | (10,308,150) |
| FAS 158 Pension Liability | (30,166,468) |
| FAS 158 Post-Retirement Liability | (11,604,974) |
| FAS 158 SERP Liability | (762,000) |
| Distribution O&M Amort of Writeoff | (168,548) |
| M&S Inventory Write-Off | (697,985) |
| Amort of Projects - Klamath Engineering | (970) |
| R & E - Sec.174 Deduction | (11,506,537) |
| Other Environmental Liabilities | (181,464) |
| Duke/Hermiston Contract Renegotiation | (754,839) |
| BPA Conservation Rate Credit | (564,504) |
| Trail Mountain Accrued Liabilities | (2,355,141) |
| Misc. Non-Current Accrued Liability | (3,073,156) |
| Misc. Current and Accrued Liability | (1,182,500) |
| Deferred Revenue - Citibank | (80,595) |
| West Valley Contract Termination Fee Accural | (6,601,499) |
| PMI Devt Cost Amort | (3,556,057) |
| Microsoft Software License Liability | (532,374) |
| Misc. Deferred Credits | (230,000) |
| Amort NOPAs 99-00 RAR | (256,755) |
| Bridger Coal Company ARO - Reg Asset | (140,894) |
| Coal Mine Extension Costs - PP&E - PMI | (2,237,229) |
| Bridger Coal Company Underground Mine Cost Depletion | (172,447) |

| | |
|---|---|
| FAS 115 Unrealized Gain/Loss | (16,914,432) |
| Bridger Coal Company Extraction Taxes Payable - PMI | (79,909) |
| Vacation Accrual - PMI | (108,413) |
| Total | (1,599,355,018) |

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

As a result of the sale of PacifiCorp to MEHC on March 21, 2006, Berkshire Hathaway 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 of PacifiCorp Holdings, Inc., PacifiCorp's former parent company.

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

**Under MEHC:**

PPW Holdings LLC Sub-Group:
PacifiCorp
PPW Holdings LLC

PacifiCorp Sub-Group:
Centralia Mining Company
Energy West Mining Company
Glenrock Coal Company
Interwest Mining Company
Pacific Minerals, Inc.
PacifiCorp Environmental Remediation Company
PacifiCorp Future Generations, Inc.
PacifiCorp Investment Management, Inc.

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 Title Services, Inc
Cimmred Leasing Company
Columbia Title of Florida, 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

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
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 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
Metro Uniforms
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
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
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 DFW, Inc.
Acme Brick Sales Company
Acme Building Brands, Inc.
Acme Investment Company
Acme Investment Company

Berkshire Hathaway Inc. Sub-Group:

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

Berkshire Hathaway Inc. Sub-Group:
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.
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, Inc.
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.
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.
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.
Harris Uniforms
Harrison Uniforms

Berkshire Hathaway Inc. Sub-Group:
HDS Redevelopment Corporation
Helzberg's Diamond Shops, Inc.
Henley Holdings, LLC
Hohmann & Barnard, Inc.
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 America Group, Inc.
International American Management Company
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.
Kale Uniforms
Kansas Bankers Surety Company
Karmelkorn Shoppes, Inc.
Kay Uniforms
Kleberg Holdings, Inc.
LA Terminals, Inc.
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 Midwest, Inc.
McLane Minnesota, Inc.
McLane New Jersey, Inc.
McLane Southern, Inc.
McLane Suneast, Inc.
McLane Western, Inc.
Medical Protective Corporation
Medical Protective Finance Corporation
Medical Protective Insurance Services, Inc.
Medical Protective Risk Retention Services, Inc.
MH Transport, Inc.
Miller Sage, 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.

Berkshire Hathaway Inc. Sub-Group:

OCSAP,Ltd.
Old City Paint & Decorating, Inc.
Orange Julius of America
Pan-Am Shoe Co., Inc.
Pima Uniforms
Pinnacle Paint & Decorating, Inc.
PJR Management Inc
Plaza Financial Services Co.
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.
Railsplitter Holdings Corporation
Rainbow State Paint & Decorating Inc.
Redwood Fire and Casualty Insurance Co.
RENTCO Trailer Corporation
Resolute Management Inc.
Ringwalt & Liesche Co
Robert f. deCastro Inc.
Roberts Men's Shop
Running with Heels (Micro Retailing, Inc.)
Russell Brands LLC (f/k/a Russell Corporation)
Russell Financial Services, Inc.
Salado Sales, Inc.
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 Serv)
Shaw Retail Properties, Inc.
Shaw Transport, Inc.
SHX Flooring, Inc.
SHX Leasing, Inc.
Silver State Uniforms
Simon's Incorporated
Simpad, Inc.
Soco West, Inc.
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.
Stahl/Scott Fetzer Company
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
TMI Custom Air Systems, Inc.
Tony Lama Company
Top Five Club, Inc.
TPC - European Holdings, Ltd.
Transco, 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.
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.

Berkshire Hathaway Inc. Sub-Group:
Vanity Fair Ventures, Inc.
Veritas Insurance Group, Inc.
Vessel Assist Association of America, Inc.
Vessel Assist Insurance Services, Inc.
VFI-Mexico, Inc.
Virginia Paint Co., Inc.
Vision Retailing
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 | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

| Line No. | Kind of Tax (See instruction 5) (a) | BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b) | Prepaid Taxes (Include in Account 165) (c) | Taxes Charged During Year (d) | Taxes Paid During Year (e) | Adjust- ments (f) |
|---|---|---|---|---|---|---|
| 1 | Federal: | | | | | |
| 2 | Income | | 31,036,759 | -63,668,990 | -46,511,544 | -9,171,551 |
| 3 | FICA | 365,997 | 40,000 | 34,359,520 | 34,250,100 | |
| 4 | Unemployment | 11,241 | | 365,656 | 367,147 | |
| 5 | Unemployment - Energy | 129,509 | | 18,432 | 52,997 | |
| 6 | Unemployment - Interwest | 108 | | 1,881 | 1,815 | |
| 7 | Excise Tax - Coal | 84,758 | | 4,253,468 | 4,248,042 | |
| 8 | Subtotal | 591,613 | 31,076,759 | -24,670,033 | -7,591,443 | -9,171,551 |
| 9 | | | | | | |
| 10 | State: | | | | | |
| 11 | | | | | | |
| 12 | Arizona: | | | | | |
| 13 | Property | 977,160 | | 1,835,630 | 1,894,975 | |
| 14 | Income | | 596,009 | -78,177 | 9,381 | -44,906 |
| 15 | Subtotal | 977,160 | 596,009 | 1,757,453 | 1,904,356 | -44,906 |
| 16 | | | | | | |
| 17 | California: | | | | | |
| 18 | Property | | | 2,057,053 | 2,057,053 | |
| 19 | Unemployment | 320 | | 33,341 | 32,164 | |
| 20 | Franchise-Income | | 119,942 | -224,046 | 429,481 | -116,358 |
| 21 | Use | 48,788 | | 144,588 | 186,125 | |
| 22 | Local Franchise | 749,835 | | 1,110,884 | 997,744 | |
| 23 | Subtotal | 798,943 | 119,942 | 3,121,820 | 3,702,567 | -116,358 |
| 24 | | | | | | |
| 25 | Colorado: | | | | | |
| 26 | Property | 1,760,000 | | 2,102,519 | 1,942,519 | |
| 27 | Income | | 172,225 | -47,915 | -55,977 | -25,580 |
| 28 | Subtotal | 1,760,000 | 172,225 | 2,054,604 | 1,886,542 | -25,580 |
| 29 | | | | | | |
| 30 | Idaho: | | | | | |
| 31 | Property | 1,483,957 | | 2,903,274 | 2,640,173 | |
| 32 | Income | | 309,568 | -395,663 | -825,942 | -209,331 |
| 33 | KWh | 500 | | 24,418 | 13,006 | |
| 34 | Unemployment | 996 | | 26,396 | 26,550 | |
| 35 | Use | 3,840 | | 277,504 | 277,983 | |
| 36 | Subtotal | 1,489,293 | 309,568 | 2,835,929 | 2,131,770 | -209,331 |
| 37 | | | | | | |
| 38 | Montana: | | | | | |
| 39 | Property | 1,192,357 | | 2,799,337 | 2,593,503 | |
| 40 | Corporate License-Income | | 321,413 | -49,906 | -62,078 | -26,579 |
| 41 | TOTAL | 20,901,699 | 44,601,542 | 95,501,425 | 109,296,502 | -14,927,776 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (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)<br>(g) | Prepaid Taxes (Incl. in Account 165)<br>(h) | Electric (Account 408.1, 409.1)<br>(i) | Extraordinary Items (Account 409.3)<br>(j) | Adjustments to Ret. Earnings (Account 439)<br>(k) | Other<br>(l) | |
| | | | | | | 1 |
| | 39,022,654 | -83,683,183 | | | 20,014,193 | 2 |
| 452,938 | 17,521 | | | | 34,359,520 | 3 |
| 9,750 | | | | | 365,656 | 4 |
| 94,944 | | | | | 18,432 | 5 |
| 174 | | | | | 1,881 | 6 |
| 90,184 | | | | | 4,253,468 | 7 |
| 647,990 | 39,040,175 | -83,683,183 | | | 59,013,150 | 8 |
| | | | | | | 9 |
| | | | | | | 10 |
| | | | | | | 11 |
| | | | | | | 12 |
| 917,815 | | 1,835,630 | | | | 13 |
| | 638,661 | -113,712 | | | 35,535 | 14 |
| 917,815 | 638,661 | 1,721,918 | | | 35,535 | 15 |
| | | | | | | 16 |
| | | | | | | 17 |
| | | 1,986,441 | | | 70,612 | 18 |
| 1,497 | | | | | 33,341 | 19 |
| | 657,111 | -325,885 | | | 101,839 | 20 |
| 7,251 | | | | | 144,588 | 21 |
| 862,975 | | 1,110,884 | | | | 22 |
| 871,723 | 657,111 | 2,771,440 | | | 350,380 | 23 |
| | | | | | | 24 |
| | | | | | | 25 |
| 1,920,000 | | 2,101,834 | | | 685 | 26 |
| | 138,583 | -69,694 | | | 21,779 | 27 |
| 1,920,000 | 138,583 | 2,032,140 | | | 22,464 | 28 |
| | | | | | | 29 |
| | | | | | | 30 |
| 1,747,058 | | 2,901,326 | | | 1,948 | 31 |
| | -330,042 | -575,509 | | | 179,846 | 32 |
| 11,912 | | 24,418 | | | | 33 |
| 842 | | | | | 26,396 | 34 |
| 3,361 | | | | | 277,504 | 35 |
| 1,763,173 | -330,042 | 2,350,235 | | | 485,694 | 36 |
| | | | | | | 37 |
| | | | | | | 38 |
| 1,398,191 | | 2,799,337 | | | | 39 |
| | 282,662 | -72,590 | | | 22,684 | 40 |
| 28,648,482 | 51,215,626 | 20,421,655 | | | 75,079,770 | 41 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

| Line No. | Kind of Tax (See instruction 5) (a) | BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b) | Prepaid Taxes (Include in Account 165) (c) | Taxes Charged During Year (d) | Taxes Paid During Year (e) | Adjust-ments (f) |
|---|---|---|---|---|---|---|
| 1 | Unemployment | | | 657 | 519 | |
| 2 | Energy License | 62,676 | | 245,970 | 248,151 | |
| 3 | Wholesale Energy | 44,657 | | 175,259 | 176,812 | |
| 4 | Subtotal | 1,299,690 | 321,413 | 3,171,317 | 2,956,907 | -26,579 |
| 5 | | | | | | |
| 6 | Nebraska: | | | | | |
| 7 | Unemployment | | | 116 | 116 | |
| 8 | Subtotal | | | 116 | 116 | |
| 9 | | | | | | |
| 10 | New Mexico: | | | | | |
| 11 | Property | 5,516 | | 10,611 | 10,821 | |
| 12 | Income | | 76 | -531 | 1,393 | -248 |
| 13 | Subtotal | 5,516 | 76 | 10,080 | 12,214 | -248 |
| 14 | | | | | | |
| 15 | Oregon: | | | | | |
| 16 | Property | 4,121 | 7,889,264 | 16,553,135 | 17,338,407 | |
| 17 | Unemployment | 39,869 | | 1,336,959 | 1,319,254 | |
| 18 | Wilsonville Payroll | 369 | | 778 | 949 | |
| 19 | Excise-Income | | -1,729,013 | -2,467,820 | -2,771,008 | -1,317,648 |
| 20 | City of Portland-Income | | 98,686 | -531 | -183,126 | -505 |
| 21 | Office of Energy | | 285,719 | 610,437 | 649,436 | |
| 22 | Tri-Met | 340,260 | | 809,782 | 802,664 | |
| 23 | Lane County | | | 2,884 | 2,884 | |
| 24 | Franchise | 3,799,889 | | 21,806,147 | 21,541,146 | |
| 25 | Subtotal | 4,184,508 | 6,544,656 | 38,651,771 | 38,700,606 | -1,318,153 |
| 26 | | | | | | |
| 27 | Utah: | | | | | |
| 28 | Property | 328,416 | | 37,662,633 | 37,109,196 | |
| 29 | Income | | 6,333,544 | -2,715,225 | -2,418,682 | -1,404,233 |
| 30 | Unemployment | 14,068 | | 244,298 | 252,732 | |
| 31 | Navajo Nation | | | 1,608 | 1,608 | |
| 32 | Use | 273,558 | | 3,442,474 | 3,299,131 | |
| 33 | Subtotal | 616,042 | 6,333,544 | 38,635,788 | 38,243,985 | -1,404,233 |
| 34 | | | | | | |
| 35 | Washington: | | | | | |
| 36 | Property | 4,300,000 | | 6,559,746 | 5,084,892 | -2,778,507 |
| 37 | Unemployment | 3,465 | | 86,397 | 80,979 | |
| 38 | Business & Occupation | 4,862 | | 6,829 | 6,523 | |
| 39 | Public Utility | 856,413 | | 9,321,317 | 9,302,730 | |
| 40 | Natural Gas Use Tax | | | 1,193,104 | 1,313,713 | -1,084,738 |
| 41 | TOTAL | 20,901,699 | 44,601,542 | 95,501,425 | 109,296,502 | -14,927,776 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (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)<br>(g) | Prepaid Taxes<br>(Incl. in Account 165)<br>(h) | Electric<br>(Account 408.1, 409.1)<br>(i) | Extraordinary Items<br>(Account 409.3)<br>(j) | Adjustments to Ret. Earnings (Account 439)<br>(k) | Other<br>(l) | |
| 138 | | | | | 657 | 1 |
| 60,495 | | 245,970 | | | | 2 |
| 43,104 | | 175,259 | | | | 3 |
| 1,501,928 | 282,662 | 3,147,976 | | | 23,341 | 4 |
| | | | | | | 5 |
| | | | | | | 6 |
| | | | | | 116 | 7 |
| | | | | | 116 | 8 |
| | | | | | | 9 |
| | | | | | | 10 |
| 5,306 | | 10,611 | | | | 11 |
| | 1,752 | -774 | | | 243 | 12 |
| 5,306 | 1,752 | 9,837 | | | 243 | 13 |
| | | | | | | 14 |
| | | | | | | 15 |
| | 8,670,415 | 16,480,864 | | | 72,271 | 16 |
| 57,574 | | | | | 1,336,959 | 17 |
| 198 | | | | | 778 | 18 |
| | -3,349,849 | -3,589,552 | | | 1,121,732 | 19 |
| | -84,414 | -772 | | | 241 | 20 |
| | 324,718 | 610,437 | | | | 21 |
| 347,378 | | | | | 809,782 | 22 |
| | | | | | 2,884 | 23 |
| 4,064,890 | | 21,806,147 | | | | 24 |
| 4,470,040 | 5,560,870 | 35,307,124 | | | 3,344,647 | 25 |
| | | | | | | 26 |
| | | | | | | 27 |
| 881,853 | | 35,691,654 | | | 1,970,979 | 28 |
| | 5,225,854 | -3,949,414 | | | 1,234,189 | 29 |
| 5,634 | | | | | 244,298 | 30 |
| | | 1,608 | | | | 31 |
| 416,901 | | | | | 3,442,474 | 32 |
| 1,304,388 | 5,225,854 | 31,743,848 | | | 6,891,940 | 33 |
| | | | | | | 34 |
| | | | | | | 35 |
| 8,553,361 | | 4,739,533 | | | 1,820,213 | 36 |
| 8,883 | | | | | 86,397 | 37 |
| 5,168 | | 6,829 | | | | 38 |
| 875,000 | | 9,321,317 | | | | 39 |
| 964,129 | | | | | 1,193,104 | 40 |
| 28,648,482 | 51,215,626 | 20,421,655 | | | 75,079,770 | 41 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

| Line No. | Kind of Tax (See instruction 5) (a) | BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b) | Prepaid Taxes (Include in Account 165) (c) | Taxes Charged During Year (d) | Taxes Paid During Year (e) | Adjust-ments (f) |
|---|---|---|---|---|---|---|
| 1 | Use | 39,724 | | 588,477 | 563,497 | |
| 2 | Retailing | 29 | | | 29 | |
| 3 | Wholesaling | | | 21,860 | 1,233 | |
| 4 | Land Tax | | | 61 | 61 | |
| 5 | Subtotal | 5,204,493 | | 17,777,791 | 16,353,657 | -3,863,245 |
| 6 | | | | | | |
| 7 | Washington D.C.: | | | | | |
| 8 | Franchise-Income | | -3,282 | -3,318 | | -36 |
| 9 | Subtotal | | -3,282 | -3,318 | | -36 |
| 10 | | | | | | |
| 11 | Wyoming: | | | | | |
| 12 | Property | 3,665,365 | | 8,672,604 | 7,986,071 | |
| 13 | Unemployment | 3,074 | | 160,112 | 158,305 | |
| 14 | Franchise | 200,300 | | 1,491,310 | 1,450,110 | |
| 15 | Use | 77,785 | | 1,030,859 | 997,260 | |
| 16 | Annual Report | | | 40,323 | 40,323 | |
| 17 | Subtotal | 3,946,524 | | 11,395,208 | 10,632,069 | |
| 18 | | | | | | |
| 19 | State Other | | -869,368 | 383,076 | | 1,252,444 |
| 20 | | | | | | |
| 21 | Miscellaneous: | | | | | |
| 22 | Goshute Possessory | | | 27,023 | | |
| 23 | Sho-Ban Possessory | | | 132,712 | 132,712 | |
| 24 | Navajo Possessory | 16,873 | | 35,122 | 34,434 | |
| 25 | Ute Possessory | | | 15,423 | 15,423 | |
| 26 | Crow Possessory | | | 62,316 | 62,316 | |
| 27 | Umatilla | | | 46,533 | 46,533 | |
| 28 | Other Taxes | 11,044 | | 60,694 | 71,738 | |
| 29 | Subtotal | 27,917 | -869,368 | 762,899 | 363,156 | 1,252,444 |
| 30 | | | | | | |
| 31 | | | | | | |
| 32 | | | | | | |
| 33 | | | | | | |
| 34 | | | | | | |
| 35 | | | | | | |
| 36 | | | | | | |
| 37 | | | | | | |
| 38 | | | | | | |
| 39 | | | | | | |
| 40 | | | | | | |
| 41 | TOTAL | 20,901,699 | 44,601,542 | 95,501,425 | 109,296,502 | -14,927,776 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (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) | |
| 64,704 | | | | | 588,477 | 1 |
| | | | | | | 2 |
| 20,627 | | | | | 21,860 | 3 |
| | | 61 | | | | 4 |
| 10,491,872 | | 14,067,740 | | | 3,710,051 | 5 |
| | | | | | | 6 |
| | | | | | | 7 |
| | | -4,826 | | | 1,508 | 8 |
| | | -4,826 | | | 1,508 | 9 |
| | | | | | | 10 |
| | | | | | | 11 |
| 4,351,898 | | 8,662,874 | | | 9,730 | 12 |
| 4,881 | | | | | 160,112 | 13 |
| 241,500 | | 1,491,310 | | | | 14 |
| 111,384 | | | | | 1,030,859 | 15 |
| | | 40,323 | | | | 16 |
| 4,709,663 | | 10,194,507 | | | 1,200,701 | 17 |
| | | | | | | 18 |
| | | 383,076 | | | | 19 |
| | | | | | | 20 |
| | | | | | | 21 |
| 27,023 | | 27,023 | | | | 22 |
| | | 132,712 | | | | 23 |
| 17,561 | | 35,122 | | | | 24 |
| | | 15,423 | | | | 25 |
| | | 62,316 | | | | 26 |
| | | 46,533 | | | | 27 |
| | | 60,694 | | | | 28 |
| 44,584 | | 762,899 | | | | 29 |
| | | | | | | 30 |
| | | | | | | 31 |
| | | | | | | 32 |
| | | | | | | 33 |
| | | | | | | 34 |
| | | | | | | 35 |
| | | | | | | 36 |
| | | | | | | 37 |
| | | | | | | 38 |
| | | | | | | 39 |
| | | | | | | 40 |
| 28,648,482 | 51,215,626 | 20,421,655 | | | 75,079,770 | 41 |

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

| | Amount | Account |
|---|---|---|
| Interest | $ 2,994 | 419 |
| Miscellaneous | 152 | 421 |
| Federal income tax accruals pursuant to FASB Interpretation No. 48 ("FIN 48") | 2,746,106 | 174 |
| Reclassification of prepaid taxes to third party receivable | (11,920,803) | 143 |
| Total adjustments | $(9,171,551) | |

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

Federal income tax applicable to other income & deductions - 409.2

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

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

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

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

**Schedule Page: 262 Line No.: 5 Column: l**

Various operations and maintenance accounts.

**Schedule Page: 262 Line No.: 6 Column: l**

Various operations and maintenance accounts.

**Schedule Page: 262 Line No.: 7 Column: l**

Fuel Inventory - 151

**Schedule Page: 262 Line No.: 14 Column: f**

| | Amount | Account |
|---|---|---|
| State income tax accruals pursuant to FASB Interpretation No. 48 ("FIN 48") | $ (15,167) | 174 |
| Reclassification of prepaid taxes to third party receivable | (29,739) | 143 |
| | $ (44,906) | |

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

State income tax applicable to other income & deductions - 409.2

**Schedule Page: 262 Line No.: 18 Column: l**

| | Amount | Account |
|---|---|---|
| Taxes applicable to other income & deductions | $ 69,738 | 408.2/409.2 |
| Distribution rent expense, rents | 874 | 589 |
| Total | $ 70,612 | |

**Schedule Page: 262 Line No.: 19 Column: l**

Various operations and maintenance accounts.

**Schedule Page: 262 Line No.: 20 Column: f**

| | Amount | Account |
|---|---|---|
| State income tax accruals pursuant to FASB Interpretation No. 48 ("FIN 48") | $ (31,128) | 174 |
| Reclassification of prepaid taxes to third party receivable | (85,230) | 143 |
| | $ (116,358) | |

**Schedule Page: 262 Line No.: 20 Column: l**

State income tax applicable to other income & deductions - 409.2

**Schedule Page: 262 Line No.: 21 Column: l**

Clearing account - 184

**Schedule Page: 262 Line No.: 26 Column: l**

Taxes applicable to other income & deductions - 408.2, 409.2

| Name of Respondent | This Report is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) X An Original<br>(2) _ A Resubmission | 03/31/2009 | 2008/Q4 |

FOOTNOTE DATA

**Schedule Page: 262 Line No.: 27 Column: f**

| | Amount | Account |
|---|---|---|
| State income tax accruals pursuant to FASB Interpretation No. 48 ("FIN 48") | $ (7,353) | 174 |
| Reclassification of prepaid taxes to third party receivable | (18,227) | 143 |
| | $ (25,580) | |

**Schedule Page: 262 Line No.: 27 Column: l**

State income tax applicable to other income & deductions - 409.2

**Schedule Page: 262 Line No.: 31 Column: l**

Taxes applicable to other income & deductions - 408.2, 409.2

**Schedule Page: 262 Line No.: 32 Column: f**

| | Amount | Account |
|---|---|---|
| State income tax accruals pursuant to FASB Interpretation No. 48 ("FIN 48") | $ (58,816) | 174 |
| Reclassification of prepaid taxes to third party receivable | (150,515) | 143 |
| | $ (209,331) | |

**Schedule Page: 262 Line No.: 32 Column: l**

State income tax applicable to other income & deductions - 409.2

**Schedule Page: 262 Line No.: 34 Column: l**

Various operations and maintenance accounts.

**Schedule Page: 262 Line No.: 35 Column: l**

Clearing account - 184

**Schedule Page: 262 Line No.: 40 Column: f**

| | Amount | Account |
|---|---|---|
| State income tax accruals pursuant to FASB Interpretation No. 48 ("FIN 48") | $ (7,594) | 174 |
| Reclassification of prepaid taxes to third party receivable | (18,985) | 143 |
| | $ (26,579) | |

**Schedule Page: 262 Line No.: 40 Column: l**

State income tax applicable to other income & deductions - 409.2

**Schedule Page: 262.1 Line No.: 1 Column: l**

Various operations and maintenance accounts.

**Schedule Page: 262.1 Line No.: 7 Column: l**

Various operations and maintenance accounts.

**Schedule Page: 262.1 Line No.: 12 Column: f**

| | Amount | Account |
|---|---|---|
| State income tax accruals pursuant to FASB Interpretation No. 48 ("FIN 48") | $ (46) | 174 |
| Reclassification of prepaid taxes to third party receivable | (202) | 143 |
| | $ (248) | |

**Schedule Page: 262.1 Line No.: 12 Column: l**

State income tax applicable to other income & deductions - 409.2

**Schedule Page: 262.1 Line No.: 16 Column: l**

| | Amount | Account |
|---|---|---|
| Taxes applicable to other income & deductions | $ 19,734 | 408.2/409.2 |
| Distribution rent expense, rents | 52,537 | 589 |
| Total | $ 72,271 | |

***Schedule Page: 262.1 Line No.: 17 Column: l***

Various operations and maintenance accounts.

***Schedule Page: 262.1 Line No.: 18 Column: l***

Various operations and maintenance accounts.

***Schedule Page: 262.1 Line No.: 19 Column: f***

| | Amount | Account |
|---|---|---|
| State income tax accruals pursuant to FASB Interpretation No. 48 ("FIN 48") | $ (378,859) | 174 |
| Reclassification of prepaid taxes to third party receivable | (938,789) | 143 |
| | $(1,317,648) | |

***Schedule Page: 262.1 Line No.: 19 Column: l***

State income tax applicable to other income & deductions - 409.2

***Schedule Page: 262.1 Line No.: 20 Column: f***

| | Amount | Account |
|---|---|---|
| State income tax accruals pursuant to FASB Interpretation No. 48 ("FIN 48") | $ (303) | 174 |
| Reclassification of prepaid taxes to third party receivable | (202) | 143 |
| | $ (505) | |

***Schedule Page: 262.1 Line No.: 20 Column: l***

State income tax applicable to other income & deductions - 409.2

***Schedule Page: 262.1 Line No.: 22 Column: l***

Various operations and maintenance accounts.

***Schedule Page: 262.1 Line No.: 23 Column: l***

Various operations and maintenance accounts.

***Schedule Page: 262.1 Line No.: 28 Column: l***

| | Amount | Account |
|---|---|---|
| Taxes applicable to other income & deductions | $ 21,185 | 408.2/409.2 |
| Fuel stock | 1,524,407 | 151 |
| Distribution rent expense, rents | 425,387 | 589 |
| Total | $ 1,970,979 | |

***Schedule Page: 262.1 Line No.: 29 Column: f***

| | Amount | Account |
|---|---|---|
| State income tax accruals pursuant to FASB Interpretation No. 48 ("FIN 48") | $ (370,066) | 174 |
| Reclassification of prepaid taxes to third party receivable | (1,034,167) | 143 |
| | $(1,404,233) | |

***Schedule Page: 262.1 Line No.: 29 Column: l***

State income tax applicable to other income & deductions - 409.2

***Schedule Page: 262.1 Line No.: 30 Column: l***

Various operations and maintenance accounts.

***Schedule Page: 262.1 Line No.: 32 Column: l***

Clearing account - 184

***Schedule Page: 262.1 Line No.: 36 Column: f***

Adjustment for the acquisition of Chehalis Power Generating, LLC in September 2008. For information regarding company acquisitions, refer to Important Changes During The Quarter/Year, Item 2 included in this Form No. 1.

***Schedule Page: 262.1 Line No.: 36 Column: l***

| | Amount | Account |
|---|---|---|
| Taxes applicable to other income & deductions | $ 117,431 | 408.2/409.2 |

| | | |
|---|---|---|
| Construction | 1,699,373 | 107 |
| Distribution rent expense, rents | 3,409 | 589 |
| Total | $ 1,820,213 | |

**Schedule Page: 262.1 Line No.: 37 Column: l**

Various operations and maintenance accounts.

**Schedule Page: 262.1 Line No.: 40 Column: f**

Adjustment for the acquisition of Chehalis Power Generating, LLC in September 2008. For information regarding company acquisitions, refer to Important Changes During The Quarter/Year, Item 2 included in this Form No. 1.

**Schedule Page: 262.1 Line No.: 40 Column: l**

Fuel Stock - 151

**Schedule Page: 262.2 Line No.: 1 Column: l**

Clearing account - 184

**Schedule Page: 262.2 Line No.: 3 Column: l**

Fuel Stock - 151

**Schedule Page: 262.2 Line No.: 8 Column: f**

| | Amount | Account |
|---|---|---|
| State income tax accruals pursuant to FASB Interpretation No. 48 ("FIN 48") | $ (36) | 174 |
| Reclassification of prepaid taxes to third party receivable | - | 143 |
| | $ (36) | |

**Schedule Page: 262.2 Line No.: 8 Column: l**

State income tax applicable to other income & deductions - 409.2

**Schedule Page: 262.2 Line No.: 12 Column: l**

| | Amount | Account |
|---|---|---|
| Taxes applicable to other income & deductions | $ 2,805 | 408.2/409.2 |
| Distribution rent expense, rents | 6,925 | 589 |
| Total | $ 9,730 | |

**Schedule Page: 262.2 Line No.: 13 Column: l**

Various operations and maintenance accounts.

**Schedule Page: 262.2 Line No.: 15 Column: l**

Clearing account - 184

**Schedule Page: 262.2 Line No.: 19 Column: f**

State income tax accruals pursuant to FIN 48 - 174

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

| Line No. | Account Subdivisions (a) | Balance at Beginning of Year (b) | Deferred for Year: Account No. (c) | Deferred for Year: Amount (d) | Allocations to Current Year's Income: Account No. (e) | Allocations to Current Year's Income: Amount (f) | Adjustments (g) |
|---|---|---|---|---|---|---|---|
| 1 | Electric Utility | | | | | | |
| 2 | 3% | | | | | | |
| 3 | 4% | | | | | | |
| 4 | 7% | | | | | | |
| 5 | 10% | 40,618,437 | | | 411.4 | 1,808,768 | |
| 6 | 10% | 10,543,126 | | | 420 | 1,624,452 | |
| 7 | Idaho | 843,329 | | | 411.4 | 65,436 | |
| 8 | TOTAL | 52,004,892 | | | | 3,498,656 | |
| 9 | Other (List separately and show 3%, 4%, 7%, 10% and TOTAL) | | | | | | |
| 10 | | | | | | | |
| 11 | | | | | | | |
| 12 | | | | | | | |
| 13 | 10% | 1,762,928 | | | 420 | 440,808 | |
| 14 | | | | | | | |
| 15 | Total Nonutility | 1,762,928 | | | | 440,808 | |
| 16 | | | | | | | |
| 17 | | | | | | | |
| 18 | | | | | | | |
| 19 | | | | | | | |
| 20 | | | | | | | |
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| 46 | | | | | | | |
| 47 | | | | | | | |
| 48 | | | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

| Balance at End of Year (h) | Average Period of Allocation to Income (i) | ADJUSTMENT EXPLANATION | Line No. |
|---|---|---|---|
| | | | 1 |
| | | | 2 |
| | | | 3 |
| | | | 4 |
| 38,809,669 | 48.37 | | 5 |
| 8,918,674 | 30 | | 6 |
| 777,893 | | | 7 |
| 48,506,236 | | | 8 |
| | | | 9 |
| | | | 10 |
| | | | 11 |
| | | | 12 |
| 1,322,120 | 30 | | 13 |
| | | | 14 |
| 1,322,120 | | | 15 |
| | | | 16 |
| | | | 17 |
| | | | 18 |
| | | | 19 |
| | | | 20 |
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| | | | 46 |
| | | | 47 |
| | | | 48 |

FOOTNOTE DATA

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

46(f)2

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

46(f)1

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $10,000, whichever is greater) may be grouped by classes.

| Line No. | Description and Other Deferred Credits<br>(a) | Balance at Beginning of Year<br>(b) | DEBITS<br>Contra Account<br>(c) | DEBITS<br>Amount<br>(d) | Credits<br>(e) | Balance at End of Year<br>(f) |
|---|---|---|---|---|---|---|
| 1 | | | | | | |
| 2 | Working Capital Deposits | 2,368,144 | | | 473,734 | 2,841,878 |
| 3 | | | | | | |
| 4 | Reclamation Costs - Trapper Mine | 4,037,459 | | | 239,153 | 4,276,612 |
| 5 | | | | | | |
| 6 | Reclamation Costs - Deseret Mine | 548,042 | 131 | 13,216 | | 534,826 |
| 7 | | | | | | |
| 8 | Reclamation Costs - Trail | | | | | |
| 9 | Mountain Mine | 1,131,538 | 131 | 4,740 | | 1,126,798 |
| 10 | | | | | | |
| 11 | Deferred Compensation Plans | 12,086,380 | 124 | 4,207,272 | 2,082,261 | 9,961,369 |
| 12 | | | | | | |
| 13 | Transmission Service Deposit | 13,155,600 | 131 | 21,648,278 | 12,023,803 | 3,531,125 |
| 14 | | | | | | |
| 15 | MCI F.O.G. wire lease | 558,468 | 454 | 3,348,954 | 3,348,583 | 558,097 |
| 16 | | | | | | |
| 17 | Redding Contract (20) | 4,400,068 | 456 | 549,996 | | 3,850,072 |
| 18 | | | | | | |
| 19 | Foote Creek Contract (15) | 980,582 | 142 | 137,640 | | 842,942 |
| 20 | | | | | | |
| 21 | Environmental Liabilities | 5,873,145 | 131 | 1,811,538 | 1,630,073 | 5,691,680 |
| 22 | | | | | | |
| 23 | Unearned Joint Use Pole Contract | 3,577,349 | 454 | 8,217,543 | 8,161,811 | 3,521,617 |
| 24 | | | | | | |
| 25 | Oregon DSM Loans NPV Unearned | 1,416,490 | 456, 431 | 699,974 | | 716,516 |
| 26 | | | | | | |
| 27 | Other Deferred Credits - C&T | 3,906,913 | 555 | 3,073,156 | | 833,757 |
| 28 | | | | | | |
| 29 | Deferred Revenue - | | | | | |
| 30 | Duke/Hermiston Gas Settlement (5) | 2,673,387 | 547, 555 | 754,838 | | 1,918,549 |
| 31 | | | | | | |
| 32 | Transmission Security Deposits | | | | 1,300,000 | 1,300,000 |
| 33 | | | | | | |
| 34 | Other deferred credits with | | | | | |
| 35 | balances less than $500,000 | 2,814,397 | various | 1,558,213 | | 1,256,184 |
| 36 | | | | | | |
| 37 | | | | | | |
| 38 | | | | | | |
| 39 | | | | | | |
| 40 | | | | | | |
| 41 | | | | | | |
| 42 | | | | | | |
| 43 | | | | | | |
| 44 | | | | | | |
| 45 | | | | | | |
| 46 | | | | | | |
| 47 | TOTAL | 59,527,962 | | 46,025,358 | 29,259,418 | 42,762,022 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

| Line No. | Account<br>(a) | Balance at Beginning of Year<br>(b) | CHANGES DURING YEAR<br>Amounts Debited to Account 410.1<br>(c) | CHANGES DURING YEAR<br>Amounts Credited to Account 411.1<br>(d) |
|---|---|---|---|---|
| 1 | Account 282 | | | |
| 2 | Electric | 1,371,109,274 | 548,099,661 | 261,436,935 |
| 3 | Gas | | | |
| 4 | FAS 109 Regulatory Asset | 459,165,634 | | |
| 5 | TOTAL (Enter Total of lines 2 thru 4) | 1,830,274,908 | 548,099,661 | 261,436,935 |
| 6 | Nonutility | 2,615,149 | | |
| 7 | | | | |
| 8 | | | | |
| 9 | TOTAL Account 282 (Enter Total of lines 5 thru | 1,832,890,057 | 548,099,661 | 261,436,935 |
| 10 | Classification of TOTAL | | | |
| 11 | Federal Income Tax | 1,613,625,194 | 482,531,627 | 230,161,773 |
| 12 | State Income Tax | 219,264,863 | 65,568,034 | 31,275,162 |
| 13 | Local Income Tax | | | |

NOTES

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

3. Use footnotes as required.

| CHANGES DURING YEAR | | ADJUSTMENTS | | | | Balance at End of Year | Line No. |
|---|---|---|---|---|---|---|---|
| Amounts Debited to Account 410.2 | Amounts Credited to Account 411.2 | Debits | | Credits | | | |
| | | Account Credited | Amount | Account Debited | Amount | | |
| (e) | (f) | (g) | (h) | (i) | (j) | (k) | |
| | | | | | | | 1 |
| | | 190 | 8,072,201 | | 4,539,916 | 1,654,239,715 | 2 |
| | | | | | | | 3 |
| | | | 19,423,849 | | | 439,741,785 | 4 |
| | | | 27,496,050 | | 4,539,916 | 2,093,981,500 | 5 |
| 701,329 | 1,573,045 | | | | | 1,743,433 | 6 |
| | | | | | | | 7 |
| | | | | | | | 8 |
| 701,329 | 1,573,045 | | 27,496,050 | | 4,539,916 | 2,095,724,933 | 9 |
| | | | | | | | 10 |
| 617,430 | 1,384,865 | | 24,206,754 | | 3,996,816 | 1,845,017,675 | 11 |
| 83,899 | 188,180 | | 3,289,296 | | 543,100 | 250,707,258 | 12 |
| | | | | | | | 13 |

NOTES (Continued)

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

Accounts
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**Schedule Page: 274 Line No.: 4 Column: g**

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(Next Page is 276)

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

| Line No. | Account<br>(a) | Balance at Beginning of Year<br>(b) | CHANGES DURING YEAR<br>Amounts Debited to Account 410.1<br>(c) | CHANGES DURING YEAR<br>Amounts Credited to Account 411.1<br>(d) |
|---|---|---|---|---|
| 1 | Account 283 | | | |
| 2 | Electric | | | |
| 3 | Regulatory Asset | 132,257,166 | 62,261,412 | 58,090,266 |
| 4 | | | | |
| 5 | Deriv. Contracts Reg. Assets | 97,163,581 | | |
| 6 | Other Deferred Liabilities | 64,648,624 | 21,018,003 | 23,365,553 |
| 7 | | | | |
| 8 | | | | |
| 9 | TOTAL Electric (Total of lines 3 thru 8) | 294,069,371 | 83,279,415 | 81,455,819 |
| 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) | 294,069,371 | 83,279,415 | 81,455,819 |
| 20 | Classification of TOTAL | | | |
| 21 | Federal Income Tax | 258,889,416 | 73,316,870 | 71,711,427 |
| 22 | State Income Tax | 35,179,955 | 9,962,545 | 9,744,392 |
| 23 | Local Income Tax | | | |

NOTES

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

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

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

| CHANGES DURING YEAR | | ADJUSTMENTS | | | | | |
|---|---|---|---|---|---|---|---|
| | | Debits | | Credits | | | |
| Amounts Debited to Account 410.2 (e) | Amounts Credited to Account 411.2 (f) | Account Credited (g) | Amount (h) | Account Debited (i) | Amount (j) | Balance at End of Year (k) | Line No. |
| | | | | | | | 1 |
| | | | | | | | 2 |
| | | | 2,199,778 | 190/282 | 137,978,279 | 272,206,813 | 3 |
| | | | | | | | 4 |
| 90,731,161 | 20,097,382 | | | | | 167,797,360 | 5 |
| 836,958 | 10,172,065 | 190/282 | 33,690,683 | 190/282 | 31,480,318 | 50,755,602 | 6 |
| | | | | | | | 7 |
| | | | | | | | 8 |
| 91,568,119 | 30,269,447 | | 35,890,461 | | 169,458,597 | 490,759,775 | 9 |
| | | | | | | | 10 |
| | | | | | | | 11 |
| | | | | | | | 12 |
| | | | | | | | 13 |
| | | | | | | | 14 |
| | | | | | | | 15 |
| | | | | | | | 16 |
| | | | | | | | 17 |
| | | | | | | | 18 |
| 91,568,119 | 30,269,447 | | 35,890,461 | | 169,458,597 | 490,759,775 | 19 |
| | | | | | | | 20 |
| 80,614,013 | 26,648,375 | | 31,596,959 | | 149,186,614 | 432,050,152 | 21 |
| 10,954,106 | 3,621,072 | | 4,293,502 | | 20,271,983 | 58,709,623 | 22 |
| | | | | | | | 23 |

NOTES (Continued)

***Schedule Page: 276 Line No.: 3 Column: g***

Accounts
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**(Next Page is 278)**

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $50,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

| Line No. | Description and Purpose of Other Regulatory Liabilities (a) | Balance at Begining of Current Quarter/Year (b) | DEBITS Account Credited (c) | DEBITS Amount (d) | Credits (e) | Balance at End of Current Quarter/Year (f) |
|---|---|---|---|---|---|---|
| 1 | FAS 109 Regulatory Liability | 22,387,221 | 190 | 1,013,945 | | 21,373,276 |
| 2 | FAS 109 - WA Flow Through | 13,399,037 | 190 | 3,605,452 | | 9,793,585 |
| 3 | OR Gain on Sales of Assets | 177,643 | | | 1,239,225 | 1,416,868 |
| 4 | SMUD Revenue Imputation (11) | 25,462,313 | 440,442 | 4,729,586 | 4,937,126 | 25,669,853 |
| 5 | Oregon Rate Refund | 79,966 | 142 | 2 | | 79,964 |
| 6 | Utah Home Energy Lifeline | 147,543 | 142 | 2,261,982 | 2,514,465 | 400,026 |
| 7 | BPA Oregon Balancing Account | | | | 988,540 | 988,540 |
| 8 | ARO/ Reg Difference - Deer Creek Mine Reclamation | 497,177 | 230 | 171,503 | 295,531 | 621,205 |
| 9 | ARO/Reg Difference - Trojan Nuclear Plant | 865,813 | 230 | 191,121 | 2,698,651 | 3,373,343 |
| 10 | Reg Liability - CA West Valley Lease Red (3) | 54,277 | 142 | 29,511 | 3,525 | 28,291 |
| 11 | Reg Liability - ID West Valley Lease Red (3) | 656,778 | 142 | 218,926 | | 437,852 |
| 12 | Reg Liability - WY West Valley Lease Red. (3) | 1,456,954 | 142 | 390,263 | 299,228 | 1,365,919 |
| 13 | Reg Liability - UT West Valley Lease Red (1.5) | 418,170 | 142 | 425,473 | 7,303 | |
| 14 | Reg Liability - A&G Credit - WA (1) | 428,241 | 142 | 438,505 | 10,264 | |
| 15 | Reg Liability - A&G Credit - CA (3) | 86,938 | 142 | 47,268 | 5,646 | 45,316 |
| 16 | Reg Liability - A&G Credit ID (3) | 676,868 | 142 | 225,623 | | 451,245 |
| 17 | Reg Liability - A&G Credit WY (3) | 1,510,795 | 142 | 443,829 | 409,784 | 1,476,750 |
| 18 | Washington Low Income Program | ( 41,964) | 142 | 1,035,030 | 1,052,413 | -24,581 |
| 19 | Reg Liability - OR Consolidation | ( 352,450) | | | 470,103 | 117,653 |
| 20 | Reg Liability - Blue Sky - OR | 462,671 | 232 | 1,151,463 | 970,106 | 281,314 |
| 21 | Reg Liability - Blue Sky - WA | 81,041 | 232 | 144,911 | 150,692 | 86,822 |
| 22 | Reg Liability - Blue Sky - CA | 34,975 | 232 | 49,706 | 62,367 | 47,636 |
| 23 | Reg Liability - Blue Sky - UT | 589,668 | 232 | 1,804,455 | 2,136,561 | 921,774 |
| 24 | Reg Liability - Blue Sky - ID | 19,977 | 232 | 24,094 | 54,617 | 50,500 |
| 25 | Reg Liability - Blue Sky - WY | 104,551 | 232 | 182,692 | 179,207 | 101,066 |
| 26 | Reg Liability - OR Energy Conser Chrg | | 232 | 6,830,798 | 7,606,672 | 775,874 |
| 27 | Reg Liability - CA Sale Gn | | | | 45,034 | 45,034 |
| 28 | Reg Liability - UT Sale Gn | | | | 1,019,355 | 1,019,355 |
| 29 | Reg Liability - ID Sale Gn | | | | 156,434 | 156,434 |
| 30 | Reg Liability - WY Sale Gn | | | | 352,888 | 352,888 |
| 31 | Reg Liability - Deferred Ben-Arch (3) | | 557.0 | 2,029,293 | 5,083,153 | 3,053,860 |
| 32 | Reg Liability - Reclass | 2,139,232 | 182.3 | 190,240 | | 1,948,992 |
| 33 | | | | | | |
| 34 | | | | | | |
| 35 | | | | | | |
| 36 | | | | | | |
| 37 | | | | | | |
| 38 | | | | | | |
| 39 | | | | | | |
| 40 | | | | | | |
| 41 | TOTAL | 71,343,435 | | 27,635,671 | 32,748,890 | 76,456,654 |

***Schedule Page: 278 Line No.: 32 Column: f***

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

| | | YTD December 31, 2008 |
|---|---|---|
| Reclassified from Regulatory Assets to Regulatory Liabilities: | | |
| California DSM Regulatory Asset | $ | 1,001,355 |
| Washington DSM Regulatory Asset | | 64,615 |
| Sch 781 Direct Access Shopping Incentive | | 845 |
| Deferred Excess Net Power Costs – CA | | 475,407 |
| Deferred UT Independent Evaulator Fee | | 93,250 |
| Deferred Intervenor Funding Grants - OR | | 266,896 |
| SB 408 Regulatory Asset - MCBIT | | 22,043 |
| | | |
| Reclassified from Regulatory Liabilities to Regulatory Assets: | | |
| Washington Low Income Program | | 24,581 |
| | $ | 1,948,992 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## ELECTRIC OPERATING REVENUES (Account 400)

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

| Line No. | Title of Account<br>(a) | Operating Revenues Year to Date Quarterly/Annual<br>(b) | Operating Revenues Previous year (no Quarterly)<br>(c) |
|---|---|---|---|
| 1 | Sales of Electricity | | |
| 2 | (440) Residential Sales | 1,345,013,663 | 1,263,790,936 |
| 3 | (442) Commercial and Industrial Sales | | |
| 4 | Small (or Comm.) (See Instr. 4) | 1,062,312,561 | 1,014,421,434 |
| 5 | Large (or Ind.) (See Instr. 4) | 998,397,465 | 914,316,590 |
| 6 | (444) Public Street and Highway Lighting | 19,865,594 | 18,902,690 |
| 7 | (445) Other Sales to Public Authorities | 18,443,905 | 17,509,459 |
| 8 | (446) Sales to Railroads and Railways | | |
| 9 | (448) Interdepartmental Sales | | |
| 10 | TOTAL Sales to Ultimate Consumers | 3,444,033,188 | 3,228,941,109 |
| 11 | (447) Sales for Resale | 860,950,758 | 856,864,831 |
| 12 | TOTAL Sales of Electricity | 4,304,983,946 | 4,085,805,940 |
| 13 | (Less) (449.1) Provision for Rate Refunds | | |
| 14 | TOTAL Revenues Net of Prov. for Refunds | 4,304,983,946 | 4,085,805,940 |
| 15 | Other Operating Revenues | | |
| 16 | (450) Forfeited Discounts | 7,486,736 | 6,784,670 |
| 17 | (451) Miscellaneous Service Revenues | 7,079,770 | 7,215,245 |
| 18 | (453) Sales of Water and Water Power | 26,406 | 107,480 |
| 19 | (454) Rent from Electric Property | 20,579,425 | 18,760,759 |
| 20 | (455) Interdepartmental Rents | | |
| 21 | (456) Other Electric Revenues | 78,876,459 | 68,728,424 |
| 22 | (456.1) Revenues from Transmission of Electricity of Others | 75,553,244 | 56,223,453 |
| 23 | (457.1) Regional Control Service Revenues | | |
| 24 | (457.2) Miscellaneous Revenues | | |
| 25 | | | |
| 26 | TOTAL Other Operating Revenues | 189,602,040 | 157,820,031 |
| 27 | TOTAL Electric Operating Revenues | 4,494,585,986 | 4,243,625,971 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## ELECTRIC OPERATING REVENUES (Account 400)

5. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
6. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
7. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
8. Include unmetered sales. Provide details of such Sales in a footnote.

| MEGAWATT HOURS SOLD | | AVG.NO. CUSTOMERS PER MONTH | | Line No. |
|---|---|---|---|---|
| Year to Date Quarterly/Annual (d) | Amount Previous year (no Quarterly) (e) | Current Year (no Quarterly) (f) | Previous Year (no Quarterly) (g) | |
| | | | | 1 |
| 16,221,455 | 15,975,228 | 1,457,645 | 1,440,688 | 2 |
| | | | | 3 |
| 16,055,182 | 15,951,322 | 210,217 | 204,569 | 4 |
| 21,494,710 | 20,892,453 | 34,172 | 34,119 | 5 |
| 141,122 | 136,080 | 4,080 | 4,230 | 6 |
| 449,314 | 435,395 | 13 | 13 | 7 |
| | | | | 8 |
| | | | | 9 |
| 54,361,783 | 53,390,478 | 1,706,127 | 1,683,619 | 10 |
| 12,344,976 | 13,723,856 | | | 11 |
| 66,706,759 | 67,114,334 | 1,706,127 | 1,683,619 | 12 |
| | | | | 13 |
| 66,706,759 | 67,114,334 | 1,706,127 | 1,683,619 | 14 |

Line 12, column (b) includes $ 210,896,000 of unbilled revenues.

Line 12, column (d) includes 3,440,267 MWH relating to unbilled revenues

**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<br>Year ended<br>December 31,<br>2008 | Page 304<br>Year ended<br>December 31,<br>2008 | Variance<br>Year ended<br>December 31,<br>2008 | |
|---|---|---|---|---|
| **Sales of Electricity** | | | | |
| Residential Sales - Account (440) | $ 1,345,013,663 | $ 1,345,013,663 | $ - | |
| Commercial and Industrial Sales - Account (442) | | | | |
| Small (Commercial) | 1,062,312,561 | 1,062,312,561 | - | |
| Large (Industrial) | 998,397,465 | 998,397,465 | - | (a) |
| Public Street and Highway Lighting - Account (444) | 19,865,594 | 19,865,594 | - | |
| Other Sales to Public Authorities - Account (445) | 18,443,905 | 18,443,905 | - | |
| Sales to Railroads and Railways - Account (446) | - | - | - | |
| Interdepartmental Sales - Account (448) | - | - | - | |
| Total Sales to Ultimate Consumers | 3,444,033,188 | 3,444,033,188 | - | |
| Sales for Resale - Account (447) | 860,950,758 | - | 860,950,758 | (b) |
| Total Sales of Electricity | 4,304,983,946 | 3,444,033,188 | 860,950,758 | |
| (less) Provision for Rate Refunds - Account (449.1) | - | - | - | |
| Total Revenues Net of Provisions for Refunds | 4,304,983,946 | 3,444,033,188 | 860,950,758 | |
| **Other Operating Revenues** | | | | |
| Forfeited Discounts - Account (450) | 7,486,736 | 7,486,736 | - | |
| Miscellaneous Service Revenues - Account (451) | 7,079,770 | 7,079,770 | - | |
| Sales of Water and Water Power - Account (453) | 26,406 | 26,406 | - | |
| Rent from Electric Property - Account (454) | 20,579,425 | 20,579,425 | - | |
| Interdepartmental Rents - Account (455) | - | | - | |
| Other Electric Revenues - Account (456) | 78,876,459 | 72,497,824 | 6,378,635 | (c) |
| Revenues from Transmission of Electricity of Others (456.1) | 75,553,244 | - | 75,553,244 | (b) |
| **Total Operating Revenues** | $ 4,494,585,986 | $ 3,551,703,349 | $ 942,882,637 | |

(a) The large industrial line on page 300 includes account 442.2 Industrial Sales of $909,975,226 and account 442.3 Irrigation Sales of $88,422,239.

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

(c) The following differences are shown between pages 300 Electricity Operating Revenue and 304 Sales of Electricity by Rate Schedules:

| | Page 300 | Page 304 | Variance |
|---|---|---|---|
| Steam Sales | $ 7,288,382 | $ - | $ 7,288,382 |
| Materials and Supplies Inventory Cost of Sales | (909,747) | - | (909,747) |
| | $ 6,378,635 | $ - | $ 6,378,635 |

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

The following table is a reconciliation of the unbilled revenue accrual at December 31, 2008 and the reversal of the December 31, 2007 unbilled revenue accrual.

| | December 31, 2008 |
|---|---|
| Current year unbilled revenue accrual | $ 210,896,000 |
| Prior year unbilled revenue accrual reversal | (192,299,000) |
| Change In Unbilled Revenue Accrual | $ 18,597,000 |

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

The following table is a reconciliation of the unbilled MWH accrual at December 31, 2008 and the reversal of the December 31, 2007 unbilled MWH accrual.

| | December 31, 2008 |
|---|---|
| Current year unbilled MWH accrual | 3,440,267 |
| Prior year unbilled MWH accrual reversal | (3,315,584) |
| Change in MWH Accrual | 124,683 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## SALES OF ELECTRICITY BY RATE SCHEDULES

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

| Line No. | Number and Title of Rate schedule (a) | MWh Sold (b) | Revenue (c) | Average Number of Customers (d) | KWh of Sales Per Customer (e) | Revenue Per KWh Sold (f) |
|---|---|---|---|---|---|---|
| 1 | RESIDENTIAL SALES | | | | | |
| 2 | CALIFORNIA | | | | | |
| 3 | 06CHCK000R-CA RES CHECK M | | | | | |
| 4 | 06LNX00102-LINE EXT 80% G | | 51 | | | |
| 5 | 06LNX00109-REF/NREF ADV + | | 471 | | | |
| 6 | 06NETMT135 - CA RES NET | 86 | 9,234 | 11 | 7,818 | 0.1074 |
| 7 | 06OALT015R-OUTD AR LGT SR | 365 | 72,707 | 391 | 934 | 0.1992 |
| 8 | 06RESD000D-RES SRVC | 205,351 | 21,756,982 | 19,047 | 10,781 | 0.1060 |
| 9 | 06RESDDL06-CA LOW INCOME | 107,293 | 11,273,482 | 9,126 | 11,757 | 0.1051 |
| 10 | 06RESDDM9M-MULTI FAMILY | 280 | 28,399 | 8 | 35,000 | 0.1014 |
| 11 | 06RESDDS8M-MULT FAM SBMET | 1,400 | 111,428 | 15 | 93,333 | 0.0796 |
| 12 | 06UPPL000R-BASE SCH FALL | | | 1 | | |
| 13 | ACQUISITION COMMITMENT-A and | | 24,929 | | | |
| 14 | ACQUISITION | | 15,564 | | | |
| 15 | SMUD REVENUE IMPUTATIONS | | 60,135 | | | |
| 16 | 06RESD00DN - CA RES SRVC - | 99,598 | 10,455,919 | 7,576 | 13,147 | 0.1050 |
| 17 | UNBILLED REV - UNCOLLECTIBLE | | -3,000 | | | |
| 18 | UNBILLED REVENUE | 3,963 | 783,000 | | | 0.1976 |
| 19 | IDAHO | | | | | |
| 20 | 07LNX00010-MNTHLY 80%GUAR | | 1,039 | | | |
| 21 | 07LNX00035-ADV 80%MO GUAR | | 2,956 | | | |
| 22 | 07NETMT135 - ID RESIDENTIAL | 122 | 8,163 | 2 | 61,000 | 0.0669 |
| 23 | 07OALCO007-CUST OWN LIGHT | 10 | 3,687 | 144 | 69 | 0.3687 |
| 24 | 07OALT07AR-SECURITY AR LG | 116 | 45,008 | 39,581 | 3 | 0.3880 |
| 25 | 07RESD0001-RES SRVC | 404,977 | 35,456,424 | | | 0.0876 |
| 26 | 07RESD0001-RES SRVC | | -231 | 16,576 | | |
| 27 | 07RESD0036-RES SRVC-OPTIO | 318,449 | 22,485,523 | | | 0.0706 |
| 28 | 07RESD0036-RES SRVC-OPTIO | | -1 | | | |
| 29 | BPA BALANCING ACCOUNT | | 290,849 | | | |
| 30 | ACQUISITION COMMITMENT-A and | | 55,467 | | | |
| 31 | ACQUISITION | | 53,821 | | | |
| 32 | SMUD REVENUE IMPUTATIONS | | -420,985 | | | |
| 33 | UNBILLED REVENUE | 3,697 | 470,000 | | | 0.1271 |
| 34 | OREGON | | | | | |
| 35 | 01CHCK000R-RES CHECK MTR | | | 1 | | |
| 36 | 01COST0004 - 01RESD0004 | 5,464,592 | 223,433,168 | | | 0.0409 |
| 37 | 01HABIT004 - 01RESD0004 | 44,799 | 1,779,422 | | | 0.0397 |
| 38 | 01LNX00102-LINE EXT 80% G | | 5,906 | | | |
| 39 | 01LNX00105-CNTRCT $ MIN G | | 38 | | | |
| 40 | 01LNX00109-REF/NREF ADV + | | 7,366 | | | |
| 41 | TOTAL Billed | 54,237,100 | 3,533,106,349 | 1,706,127 | 31,790 | 0.0651 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 124,683 | 18,597,000 | 0 | 0 | 0.1492 |
| 43 | TOTAL | 54,361,783 | 3,551,703,349 | 1,706,127 | 31,863 | 0.0653 |

| Name of Respondent PacifiCorp | This Report Is: (1) [X] An Original (2) [ ] A Resubmission | Date of Report (Mo, Da, Yr) 03/31/2009 | Year/Period of Report End of 2008/Q4 |
|---|---|---|---|

## SALES OF ELECTRICITY BY RATE SCHEDULES

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

| Line No. | Number and Title of Rate schedule (a) | MWh Sold (b) | Revenue (c) | Average Number of Customers (d) | KWh of Sales Per Customer (e) | Revenue Per KWh Sold (f) |
|---|---|---|---|---|---|---|
| 1 | 01NETMT135-NET METERING | | 210,372 | 477 | | |
| 2 | 01NETMT135-NET METERING | | -3,062 | | | |
| 3 | 01OALT014R-OUTD AR LGT RE | 2,683 | 384,308 | 3,001 | 894 | 0.1432 |
| 4 | 01OALT014R-OUTD AR LGT RE | | -1,097 | | | |
| 5 | 01PTOU0004 - 01RESD0004 | 19,961 | 816,281 | | | 0.0409 |
| 6 | 01RENEW004 - 01RESD0004 | 183,971 | 7,204,179 | | | 0.0392 |
| 7 | 01RESD0004-RES SRVC | -2 | 246,583,035 | 469,691 | | -123,291.5175 |
| 8 | 01RESD0004-RES SRVC | | -2,717,055 | | | |
| 9 | 01RESD004T - RES Time Option | | 852,635 | 1,268 | | |
| 10 | 01RESD004T - RES Time Option | | -10,228 | | | |
| 11 | 01UPPL000R-BASE SCH FALL | | | 3 | | |
| 12 | BPA BALANCING ACCOUNT | | -1,157,172 | | | |
| 13 | OR SB408 RECOVERY | | 10,644,576 | | | |
| 14 | OR SB 838 RECOVERY | | 4,429,225 | | | |
| 15 | SMUD REVENUE IMPUTATIONS | | 747,414 | | | |
| 16 | UNBILLED REV - UNCOLLECTIBLE | | -12,000 | | | |
| 17 | UNBILLED REVENUE | 90,621 | 8,038,000 | | | 0.0887 |
| 18 | UTAH | | | | | |
| 19 | 08BLSKY01R-BLUESKY ENERGY | | -3 | | | |
| 20 | 08CFR00001-MTH FACILITY S | | 1,409 | | | |
| 21 | 08CHCK000R-UT RES CHECK M | | | | | |
| 22 | 08COOLKPRR - Utah Cool Keeper | | | 70,703 | | |
| 23 | 08LNX00001-MTHLY 80% GUAR | | 1,509 | | | |
| 24 | 08LNX00013-80% MNTHLY MIN | | 21,636 | | | |
| 25 | 08LNX00108-ANN COST MTHLY | | 3,981 | | | |
| 26 | 08MHTP0025-MOBILE HOME & | 12,008 | 821,388 | 11 | 1,091,636 | 0.0684 |
| 27 | 08NETMT135 - Net Metering | 1,467 | 121,710 | 215 | 6,823 | 0.0830 |
| 28 | 08OALT007R-SECURITY AR LG | 2,923 | 781,330 | 3,248 | 900 | 0.2673 |
| 29 | 08PTLD000R-POST TOP LIGHT | 224 | 16,849 | 67 | 3,343 | 0.0752 |
| 30 | 08RESD0001-RES SRVC | 6,342,774 | 525,723,257 | 669,820 | 9,469 | 0.0829 |
| 31 | 08RESD0002-RES SRVC-OPTIO | 2,557 | 208,885 | 294 | 8,697 | 0.0817 |
| 32 | 08RESD0003-LIFELINE PRGRM | 182,653 | 14,918,754 | 23,358 | 7,820 | 0.0817 |
| 33 | 08UPPL000R-BASE SCH FALL | | | 3 | | |
| 34 | 08ZZMERGCR-MERGER CREDITS | | -21 | | | |
| 35 | ACQUISITION | | 125,812 | | | |
| 36 | SMUD REVENUE IMPUTATIONS | | 631,764 | | | |
| 37 | UNBILLED REV - UNCOLLECTIBLE | | 10,000 | | | |
| 38 | UNBILLED REVENUE | 15,973 | 2,173,000 | | | 0.1360 |
| 39 | WASHINGTON | | | | | |
| 40 | 02LNX00109-REF/NREF ADV + | | 584 | | | |
| 41 | TOTAL Billed | 54,237,100 | 3,533,106,349 | 1,706,127 | 31,790 | 0.0651 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 124,683 | 18,597,000 | 0 | 0 | 0.1492 |
| 43 | TOTAL | 54,361,783 | 3,551,703,349 | 1,706,127 | 31,863 | 0.0653 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## SALES OF ELECTRICITY BY RATE SCHEDULES

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

| Line No. | Number and Title of Rate schedule (a) | MWh Sold (b) | Revenue (c) | Average Number of Customers (d) | KWh of Sales Per Customer (e) | Revenue Per KWh Sold (f) |
|---|---|---|---|---|---|---|
| 1 | 02NETMT135 - WA RES NET | 16 | 1,046 | 3 | 5,333 | 0.0654 |
| 2 | 02NETMT135 - WA RES NET | | -10 | | | |
| 3 | 02OALTB15R-WA OUTD AR LGT | 1,131 | 150,853 | 1,223 | 925 | 0.1334 |
| 4 | 02OALTB15R-WA OUTD AR LGT | | -259 | | | |
| 5 | 02RESD0016-WA RES SRVC | 1,558,123 | 104,829,336 | 99,024 | 15,735 | 0.0673 |
| 6 | 02RESD0016-WA RES SRVC | | -570,130 | | | |
| 7 | 02RESD0017-BILL ASSISTANC | 64,105 | 4,317,854 | 3,814 | 16,808 | 0.0674 |
| 8 | 02RESD0017-BILL ASSISTANCE | | -25,904 | | | |
| 9 | 02RESD0018-WA 3 PHASE RES | 2,618 | 193,707 | 98 | 26,714 | 0.0740 |
| 10 | 02RESD0018-WA 3 PHASE RES | | -842 | | | |
| 11 | 02RESD018X-WA 3 PHASE RES | 603 | 43,737 | 25 | 24,120 | 0.0725 |
| 12 | 02RESD018X-WA 3 PHASE RES | | -186 | | | |
| 13 | 02RFNDCENT - CENTRALIA RFND | | -1 | | | |
| 14 | 02ZZMERGCR-MERGER CREDITS | | 4 | | | |
| 15 | ACQUISITION COMMITMENT-A and | | 194 | | | |
| 16 | BPA BALANCING ACCOUNT | | -522,412 | | | |
| 17 | SMUD REVENUE IMPUTATIONS | | -833,183 | | | |
| 18 | UNBILLED REV - UNCOLLECTIBLE | | 1,000 | | | |
| 19 | UNBILLED REVENUE | -675 | 271,000 | | | -0.4015 |
| 20 | WYOMING | | | | | |
| 21 | 05LNX00109-REF/NREF ADV + | | 790 | | | |
| 22 | 05NETMT135 - EXPERIMENTAL | 285 | 22,313 | 24 | 11,875 | 0.0783 |
| 23 | 05OALT015R-OUTD AR LGT SR | 994 | 154,169 | 1,148 | 866 | 0.1551 |
| 24 | 05RES00002-WY OPTIONAL | 55,487 | 3,819,593 | 4,085 | 13,583 | 0.0688 |
| 25 | 05RESD0002-WY RES SRVC | 870,219 | 70,489,991 | 93,212 | 9,336 | 0.0810 |
| 26 | 05RESD0018-RES 3 PHASE SR | 113 | 8,191 | 9 | 12,556 | 0.0725 |
| 27 | 05RESD018X-RES 3 PHASE SR | 174 | 12,396 | 2 | 87,000 | 0.0712 |
| 28 | 05RFNDCENT-CENTRALIA RFND | | -8 | | | |
| 29 | ACQUISITION COMMITMENT-A and | | 20,852 | | | |
| 30 | ACQUISITION | | 16,095 | | | |
| 31 | SMUD REVENUE IMPUTATIONS | | 102,343 | | | |
| 32 | 09NETMT135 - WY RES NET | | 497 | 4 | | |
| 33 | 09RESD0002 | 136 | 9,972 | 26 | 5,231 | 0.0733 |
| 34 | UNBILLED REV - UNCOLLECTIBLE | | -22,000 | | | |
| 35 | UNBILLED REVENUE | 17,186 | 1,736,000 | | | 0.1010 |
| 36 | 05RESD0002-WY RES SRVC | 75,432 | 6,292,233 | 8,381 | 9,000 | 0.0834 |
| 37 | 05RESD0018-RES 3 PHASE SR | 1 | 130 | 1 | 1,000 | 0.1300 |
| 38 | 05UPPL000R-BASE SCH FALL | | | 1 | | |
| 39 | 09OALT207R-SECURITY AR LG | 87 | 25,093 | 101 | 861 | 0.2884 |
| 40 | 09NETMT135 - WY RES NET | 32 | 2,109 | 1 | 32,000 | 0.0659 |
| | | | | | | |
| 41 | TOTAL Billed | 54,237,100 | 3,533,106,349 | 1,706,127 | 31,790 | 0.0651 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 124,683 | 18,597,000 | 0 | 0 | 0.1492 |
| 43 | TOTAL | 54,361,783 | 3,551,703,349 | 1,706,127 | 31,863 | 0.0653 |

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|---|---|---|---|---|---|---|
| 1 | CUSTOMER COUNT - REGULAR | | | | | |
| 2 | SMUD REVENUE IMPUTATIONS | | 8,785 | | | |
| 3 | 05RES00002-WY OPTIONAL | 46 | 3,158 | 5 | 9,200 | 0.0687 |
| 4 | 05NETMT135 - EXPERIMENTAL | 47 | 3,417 | 2 | 23,500 | 0.0727 |
| 5 | 09RES00002 | 20,563 | 1,429,009 | 741 | 27,750 | 0.0695 |
| 6 | 09RESD0002 | 41,548 | 3,118,555 | 3,380 | 12,292 | 0.0751 |
| 7 | UNBILLED REVENUE | 273 | 66,000 | | | 0.2418 |
| 8 | LESS MULTIPLE BILLINGS | | | -92,303 | | |
| 9 | | | | | | |
| 10 | TOTAL RESIDENTIAL SALES | 16,221,455 | 1,345,013,663 | 1,457,645 | 11,129 | 0.0829 |
| 11 | | | | | | |
| 12 | COMMERCIAL SALES | | | | | |
| 13 | CALIFORNIA | | | | | |
| 14 | 06CHCK000N-CA NRES CHECK | | | 1 | | |
| 15 | 06GNSV0025-CA GEN SRVC | 65,447 | 8,242,032 | 6,912 | 9,469 | 0.1259 |
| 16 | 06GNSV025F-GEN SRVC-< 20 | 948 | 135,265 | 93 | 10,194 | 0.1427 |
| 17 | 06GNSV0A32-GEN SRVC-20 KW | 79,767 | 8,321,451 | 878 | 90,851 | 0.1043 |
| 18 | 06LGSV048T-LRG GEN SERV | 71,047 | 4,774,991 | 10 | 7,104,700 | 0.0672 |
| 19 | 06LGSV0A36-LRG GEN SRVC-O | 84,923 | 7,403,738 | 192 | 442,307 | 0.0872 |
| 20 | 06LNX00102-LINE EXT 80% G | | 12,878 | | | |
| 21 | 06LNX00105-CNTRCT $ MIN G | | 4,606 | | | |
| 22 | 06LNX00109-REF/NREF ADV + | | 77,643 | | | |
| 23 | 06LNX00300 - 80% MONTHLY MIN | | 3,983 | | | |
| 24 | 06LNX00311 - LINE EXT 80% | | 718 | | | |
| 25 | 06OALT015N-OUTD AR LGT SR | 751 | 151,111 | 545 | 1,378 | 0.2012 |
| 26 | 06RCFL0042-AIRWAY & ATHLE | 203 | 30,834 | 39 | 5,205 | 0.1519 |
| 27 | 06WHSV0031-COMM WTR HEATI | 221 | 23,833 | 29 | 7,621 | 0.1078 |
| 28 | 06NMT32135-CA GEN SVC NET | 14 | 1,494 | 1 | 14,000 | 0.1067 |
| 29 | ACQUISITION COMMITMENT-A and | | 18,404 | | | |
| 30 | ACQUISITION | | 11,490 | | | |
| 31 | SMUD REVENUE IMPUTATIONS | | 45,591 | | | |
| 32 | 06LNX00110-REF/NREF ADV + | | 5,698 | | | |
| 33 | UNBILLED REVENUE | 936 | 211,000 | | | 0.2254 |
| 34 | IDAHO | | | | | |
| 35 | 07CISH0019-COMM & IND SPA | 8,796 | 593,236 | 191 | 46,052 | 0.0674 |
| 36 | 07GNSV0006-GEN SRVC-LRG P | 193,001 | 11,842,510 | 935 | 206,418 | 0.0614 |
| 37 | 07GNSV0009-GEN SRVC-HI VO | 32,424 | 1,430,828 | 1 | 32,424,000 | 0.0441 |
| 38 | 07GNSV0023-GEN SRVC-SML P | 118,254 | 9,441,262 | 5,962 | 19,835 | 0.0798 |
| 39 | 07GNSV0035-GEN SRVCOPTION | 648 | 44,375 | 2 | 324,000 | 0.0685 |
| 40 | 07GNSV006A-GEN SRVC-LRG P | 30,575 | 1,973,616 | 216 | 141,551 | 0.0646 |
| | | | | | | |
| 41 | TOTAL Billed | 54,237,100 | 3,533,106,349 | 1,706,127 | 31,790 | 0.0651 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 124,683 | 18,597,000 | 0 | 0 | 0.1492 |
| 43 | TOTAL | 54,361,783 | 3,551,703,349 | 1,706,127 | 31,863 | 0.0653 |

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|---|---|---|---|---|---|---|
| 1 | 07GNSV006A-GEN SRVC-LRG P | | -1 | | | |
| 2 | 07GNSV023A-GEN SRVC-SML P | 16,038 | 1,322,905 | 1,151 | 13,934 | 0.0825 |
| 3 | 07GNSV023A-GEN SRVC-SML P | | 241 | | | |
| 4 | 07GNSV023F-GEN SRVC SML P | 19 | 2,687 | 7 | 2,714 | 0.1414 |
| 5 | 07LNX00010-MNTHLY 80%GUAR | | 11,670 | | | |
| 6 | 07LNX00035-ADV 80%MO GUAR | | 293,307 | | | |
| 7 | 07LNX00040-ADV+REFCHG+80% | | 33,533 | | | |
| 8 | 07OALT007N-SECURITY AR LG | 253 | 91,363 | 191 | 1,325 | 0.3611 |
| 9 | 07OALT07AN-SECURITY AR LG | 13 | 4,867 | 15 | 867 | 0.3744 |
| 10 | 07LNX00312 - ID LINE EXT | | 1,261 | | | |
| 11 | 07NMT23135 - ID NET MTR - | 3 | 256 | 1 | 3,000 | 0.0853 |
| 12 | 07LNX00015-ANNUAL 80%GUAR | | 1,163 | | | |
| 13 | 07LNX00311 - LINE EXT 80% | | 20,323 | | | |
| 14 | 07LNX00020 - ID MONTHLY | | 611 | | | |
| 15 | 07LNX00300 - 80% MONTHLY MIN | | 1,546 | | | |
| 16 | ACQUISITION COMMITMENT-A and | | 32,248 | | | |
| 17 | ACQUISITION | | 31,291 | | | |
| 18 | BPA BALANCING ACCOUNT | | 168 | | | |
| 19 | SMUD REVENUE IMPUTATIONS | | -239,232 | | | |
| 20 | UNBILLED REVENUE | -1,598 | -67,000 | | | 0.0419 |
| 21 | OREGON | | | | | |
| 22 | 01COST0023, OR GEN SRV, COST | 997,134 | 41,268,054 | | | 0.0414 |
| 23 | 01COST0048 - 01LGSV0048 | 760,789 | 28,737,882 | | | 0.0378 |
| 24 | 01COST023F - OR GEN SRV - | 3,167 | 139,879 | | | 0.0442 |
| 25 | 01COSTB023 - OR GEN SRV, | 91,613 | 3,931,347 | | | 0.0429 |
| 26 | 01COSTL030 - OR LRG GEN SRV, | 1,055,918 | 41,744,837 | | | 0.0395 |
| 27 | 01COSTS028, OR GEN SERV, | 1,973,039 | 80,323,358 | | | 0.0407 |
| 28 | 01COSTS030 - OR GEN SRV CBS > | 1,096 | 38,633 | | | 0.0352 |
| 29 | 01GNSB0023 - BPA DISC, < 30 kW | | -42,190 | | | |
| 30 | 01GNSB0023, OR GEN SRV, BPA, | | 5,100,202 | 14,494 | | |
| 31 | 01GNSB0028 - OR GEN SRVC, | | -71,868 | | | |
| 32 | 01GNSB0028, OR GEN SRV, BPA, | | 2,872,758 | 577 | | |
| 33 | 01GNSB023T - OR GEN SRV - TOU | | 26,948 | 55 | | |
| 34 | 01GNSB023T - OR GEN SRVC, | | -264 | | | |
| 35 | 01GNSV0023, OR GEN SRV, < 30 | -6 | 36,744,915 | 55,182 | | -6,124.1525 |
| 36 | 01GNSV0028, OR GEN SRV > 30 | | 41,052,982 | 8,998 | | |
| 37 | 01GNSV023F - OR GEN SRV - | 9,889 | 1,207,017 | 864 | 11,446 | 0.1221 |
| 38 | 01GNSV023M - OR GEN SRV, | 18 | 1,496 | 1 | 18,000 | 0.0831 |
| 39 | 01GNSV023T, OR GEN SRV, TOU | | 161,912 | 243 | | |
| 40 | 01HABT0023, OR HABITAT | 2,226 | 92,877 | | | 0.0417 |
| | | | | | | |
| 41 | TOTAL Billed | 54,237,100 | 3,533,106,349 | 1,706,127 | 31,790 | 0.0651 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 124,683 | 18,597,000 | 0 | 0 | 0.1492 |
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## SALES OF ELECTRICITY BY RATE SCHEDULES

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6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

| Line No. | Number and Title of Rate schedule (a) | MWh Sold (b) | Revenue (c) | Average Number of Customers (d) | KWh of Sales Per Customer (e) | Revenue Per KWh Sold (f) |
|---|---|---|---|---|---|---|
| 1 | 01HABTB023 - OR HABITAT | 168 | 7,422 | | | 0.0442 |
| 2 | 01LGSB0030, GEN DEL SRV, > 200 | | -26,637 | | | |
| 3 | 01LGSB0030, GEN DEL SRV, > 200 | | 882,059 | 33 | | |
| 4 | 01LGSV0030 - OR LRG GEN SRV, | | 16,605,197 | 639 | | |
| 5 | 01LGSV0048-1000KW AND OVR | | 7,897,065 | 95 | | |
| 6 | 01LGSV048M-LRG GEN SRVC 1 | 52,699 | 2,253,981 | 1 | 52,699,000 | 0.0428 |
| 7 | 01LNX00100-LINE EXT 60% G | | 8,550 | | | |
| 8 | 01LNX00102-LINE EXT 80% G | | 433,328 | | | |
| 9 | 01LNX00103-LINE EXT 80% G | | 3,054 | | | |
| 10 | 01LNX00105-CNTRCT $ MIN G | | 15,347 | | | |
| 11 | 01LNX00109-REF/NREF ADV + | | 1,826,874 | | | |
| 12 | 01LNX00110-REF/NREF ADV + | | 14,221 | | | |
| 13 | 01LNX00300 - LINE EXT 80% | | 76,125 | | | |
| 14 | 01LNX00311 - LINE EXT 80% G | | 45,654 | | | |
| 15 | 01LNX00312 - OR IRG LINE EXT | | -175 | | | |
| 16 | 01LPRS047M-PART REQ SRVC | 3,638 | 383,293 | 3 | 1,212,667 | 0.1054 |
| 17 | 01NMT23135 - OR NET MTR, GEN, | | 27,439 | 44 | | |
| 18 | 01OALT014N-OUTD AR LGT NR | 1,674 | 247,618 | 1,196 | 1,400 | 0.1479 |
| 19 | 01OALT014N-OUTD AR LGT NR | | -710 | | | |
| 20 | 01OALT015N-OUTD AR LGT NR | 6,273 | 797,251 | 3,151 | 1,991 | 0.1271 |
| 21 | 01PTOU0023, OR GEN SRV, TOU | 4,076 | 165,726 | | | 0.0407 |
| 22 | 01PTOUB023, OR GEN SRV, TOU | 596 | 24,172 | | | 0.0406 |
| 23 | 01RCFL0054-REC FIELD LGT | 1,057 | 92,713 | 102 | 10,363 | 0.0877 |
| 24 | 01RENW0023, OR RENW USAGE | 8,460 | 357,684 | | | 0.0423 |
| 25 | 01RENWB023 - OR RENEWABLE | 598 | 26,157 | | | 0.0437 |
| 26 | 01STDAY023 - OR DAY STD OFR, | 1,878 | 116,845 | | | 0.0622 |
| 27 | 01STDAY028 - OR DAY STD OFF, | 3,123 | 193,459 | | | 0.0619 |
| 28 | 01STDAY030 - OR STD DAY OFF, | 4,480 | 275,227 | | | 0.0614 |
| 29 | BPA BALANCING ACCOUNT | | -65,160 | | | |
| 30 | 01LGSB0048 - LG GEN SVC > | | -1,851 | | | |
| 31 | 01LGSB0048 - LG GEN SVC > | | 47,471 | 1 | | |
| 32 | 01NMT28135 - OR NET MTR, GEN, | | 58,107 | 12 | | |
| 33 | 01NMT30135 - OR NET MTR, GEN, | | 3,962 | 2 | | |
| 34 | 01LGSV028M - OR LGSV, <1000 | 350 | 25,060 | 1 | 350,000 | 0.0716 |
| 35 | 01GNSV030M - OR GEN SRV, 200 | 2,345 | 124,084 | 1 | 2,345,000 | 0.0529 |
| 36 | 01GNSV0728 - OR GEN SVC DIR | | 32,088 | 2 | | |
| 37 | 01GNSV0730 -OR GEN SVC DIR | | 841,478 | 37 | | |
| 38 | 01GNSV0748 LG GEN SVC DIR | | 35,863 | 1 | | |
| 39 | OR SB408 RECOVERY | | 9,366,575 | | | |
| 40 | OR SB 838 RECOVERY | | 3,731,684 | | | |
| | | | | | | |
| 41 | TOTAL Billed | 54,237,100 | 3,533,106,349 | 1,706,127 | 31,790 | 0.0651 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 124,683 | 18,597,000 | 0 | 0 | 0.1492 |
| 43 | TOTAL | 54,361,783 | 3,551,703,349 | 1,706,127 | 31,863 | 0.0653 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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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 | SMUD REVENUE IMPUTATIONS | | 655,031 | | | |
| 2 | UNBILLED REVENUE | 13,795 | 967,000 | | | 0.0701 |
| 3 | UTAH | | | | | |
| 4 | 08CFR00051-MTH FAC SRVCHG | | 44,155 | | | |
| 5 | 08CFR00052-ANN FAC SVCCHG | | 2 | | | |
| 6 | 08CHCK000N-UT NRES CHECK | | | 3 | | |
| 7 | 08COOLKPRN - A/C DIRECT LOAD | | | 2,285 | | |
| 8 | 08GNSV0006-GEN SRVC-DISTR | 4,754,623 | 304,069,070 | 11,146 | 426,577 | 0.0640 |
| 9 | 08GNSV0009-GEN SRVC-HI VO | 241,245 | 10,330,417 | 18 | 13,402,500 | 0.0428 |
| 10 | 08GNSV0023-GEN SRVC-DISTR | 1,204,527 | 92,648,532 | 66,055 | 18,235 | 0.0769 |
| 11 | 08GNSV006A-GEN SRVC-ENERG | 196,695 | 16,666,562 | 1,700 | 115,703 | 0.0847 |
| 12 | 08GNSV006B-GEN SRVC-DEM& | 2,920 | 193,133 | 12 | 243,333 | 0.0661 |
| 13 | 08GNSV006M-MNL DIST VOLTG | 3,154 | 170,815 | 7 | 450,571 | 0.0542 |
| 14 | 08GNSV009A-GEN SRVC HI VO | 25,210 | 1,202,659 | 2 | 12,605,000 | 0.0477 |
| 15 | 08GNSV009M-MANL HIGH VOLT | 19,949 | 834,760 | 1 | 19,949,000 | 0.0418 |
| 16 | 08GNSV023F-GEN SRVC FIXED | 1,422 | 150,813 | 121 | 11,752 | 0.1061 |
| 17 | 08GNSV023M-GNSV DIST VOLT | 108 | 8,481 | 6 | 18,000 | 0.0785 |
| 18 | 08GNSV06AM-MNL ENERGY TOD | 425 | 49,113 | 2 | 212,500 | 0.1156 |
| 19 | 08GNSV06MN-GNSV DIST VOLT | 26,731 | 1,586,289 | 432 | 61,877 | 0.0593 |
| 20 | 08LNX00002-MTHLY 80% GUAR | | 550,678 | | | |
| 21 | 08LNX00004-ANNUAL 80%GUAR | | 79,129 | | | |
| 22 | 08LNX00006-FIXD MTHLY MIN | | 14,237 | | | |
| 23 | 08LNX00014-80% MIN MNTHLY | | 2,171,333 | | | |
| 24 | 08LNX00017-ADV/REF&80%ANN | | 112,144 | | | |
| 25 | 08LNX00158-ANNUALCOST MTH | | 32,954 | | | |
| 26 | 08LNX00300 - LINE EXT 80% PLUS | | 199,592 | | | |
| 27 | 08LNX00310 - IRR, 80% ANNUAL | | 4,064 | | | |
| 28 | 08LNX00312 UT IRG LINE EXT | | 2,557 | | | |
| 29 | 08NMT23135 - UT NET MTR, GEN, | 239 | 19,709 | 16 | 14,938 | 0.0825 |
| 30 | 08OALT007N-SECURITY AR LG | 9,152 | 1,980,531 | 4,708 | 1,944 | 0.2164 |
| 31 | 08POLE0075-POLES W/LIGHT | | 324 | 2 | | |
| 32 | 08PRSV031M-BKUP MNT&SUPPL | 14,711 | 849,963 | 3 | 4,903,667 | 0.0578 |
| 33 | 08PTLD000N-POST TOP LIGHT | 62 | 4,636 | 7 | 8,857 | 0.0748 |
| 34 | 08TOSS015F-TRAFFIC SIG NM | 231 | 18,725 | 32 | 7,219 | 0.0811 |
| 35 | 08TOSS0015-TRAF & OTHER | 1,129 | 94,566 | 442 | 2,554 | 0.0838 |
| 36 | 08MONL0015-MTR OUTDONIGHT | 11,863 | 811,009 | 297 | 39,943 | 0.0684 |
| 37 | ACQUISITION | | 148,023 | | | |
| 38 | SMUD REVENUE IMPUTATIONS | | 716,757 | | | |
| 39 | 08LNX00311 - LINE EXT 80% | | 82,321 | | | |
| 40 | 08GNSV0008 - UT GEN SVC TOU > | 929,745 | 51,526,219 | 133 | 6,990,564 | 0.0554 |
| | | | | | | |
| 41 | TOTAL Billed | 54,237,100 | 3,533,106,349 | 1,706,127 | 31,790 | 0.0651 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 124,683 | 18,597,000 | 0 | 0 | 0.1492 |
| 43 | TOTAL | 54,361,783 | 3,551,703,349 | 1,706,127 | 31,863 | 0.0653 |

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|---|---|---|---|---|---|---|
| 1 | 08GNSV008M - UT GEN SVC TOU | 38,964 | 2,272,116 | 5 | 7,792,800 | 0.0583 |
| 2 | UNBILLED REVENUE | -42,172 | -1,890,000 | | | 0.0448 |
| 3 | WASHINGTON | | | | | |
| 4 | 02GNSB0024-WA GEN SRVC DO | 41,173 | 3,018,724 | 3,203 | 12,855 | 0.0733 |
| 5 | 02GNSB0024-WA GEN SRVC DO | | -12,657 | | | |
| 6 | 02GNSB024F-GEN SRVC DOM/F | 215 | 19,843 | 8 | 26,875 | 0.0923 |
| 7 | 02GNSB024F-GEN SRVC DOM/F | | -4 | | | |
| 8 | 02GNSB24FP-WA GEN SVC | 644 | 123,968 | 104 | 6,192 | 0.1925 |
| 9 | 02GNSB24FP-WA GEN SVC | | -20 | | | |
| 10 | 02GNSV0024-WA GEN SRVC | 472,047 | 31,457,816 | 13,827 | 34,140 | 0.0666 |
| 11 | 02GNSV024F-WA GEN SRVC-FL | 1,207 | 120,541 | 121 | 9,975 | 0.0999 |
| 12 | 02LGSB0036-LRG GEN SVC IRG | 77,132 | 4,256,415 | 91 | 847,604 | 0.0552 |
| 13 | 02LGSB0036-LRG GENSVC IRG | | -26,392 | | | |
| 14 | 02LGSV0036-WA LRG GEN SRV | 680,057 | 38,135,069 | 808 | 841,655 | 0.0561 |
| 15 | 02LGSV048T-LRG GEN SRVC 1 | 134,165 | 6,837,482 | 25 | 5,366,600 | 0.0510 |
| 16 | 02LNX00102-LINE EXT 80% G | | 55,319 | | | |
| 17 | 02LNX00103-LINE EXT 80% G | | 2,746 | | | |
| 18 | 02LNX00105-CNTRCT $ MIN G | | 883 | | | |
| 19 | 02LNX00109-REF/NREF ADV + | | 210,983 | | | |
| 20 | 02LNX00110-REF/NREF ADV + | | 13,948 | | | |
| 21 | 02LNX00112-YR INCURRED CH | | 669 | | | |
| 22 | 02LNX00300-LINE EXT 80% G | | 3,746 | | | |
| 23 | 02LNX00310 - IRG, 80% ANNUAL | | 2,685 | | | |
| 24 | 02LNX00311 - LINE EXT 80% | | 14,236 | | | |
| 25 | 02OALT015N-WA OUTD AR LGT | 1,686 | 207,837 | 876 | 1,925 | 0.1233 |
| 26 | 02OALTB15N-WA OUTD AR LGT | 631 | 83,454 | 548 | 1,151 | 0.1323 |
| 27 | 02OALTB15N-WA OUTD AR LGT | | -190 | | | |
| 28 | 02RCFL0054-WA REC FIELD L | 261 | 21,082 | 29 | 9,000 | 0.0808 |
| 29 | 02RFNDCENT - CENTRALIA RFND | | 7 | | | |
| 30 | 02ZZMERGCR-MERGER CREDITS | | 7 | | | |
| 31 | 02NMT24135, Net metering, WA | 2 | 91 | 1 | 2,000 | 0.0455 |
| 32 | ACQUISITION COMMITMENT-A and | | 173 | | | |
| 33 | BPA BALANCING ACCOUNT | | -58,012 | | | |
| 34 | SMUD REVENUE IMPUTATIONS | | -728,628 | | | |
| 35 | UNBILLED REVENUE | -5,093 | 120,000 | | | -0.0236 |
| 36 | WYOMING | | | | | |
| 37 | 05CHCK000N-WY NRES | | | 1 | | |
| 38 | 05GNSV0025-WY GEN SRVC | 1,120,248 | 76,659,924 | 20,821 | 53,804 | 0.0684 |
| 39 | 05GNSV025F-GEN SRVC-FL RA | 1,002 | 121,446 | 191 | 5,246 | 0.1212 |
| 40 | 05LGSV0046-WY LRG GEN SRV | 205,752 | 10,845,667 | 19 | 10,829,053 | 0.0527 |
| | | | | | | |
| 41 | TOTAL Billed | 54,237,100 | 3,533,106,349 | 1,706,127 | 31,790 | 0.0651 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 124,683 | 18,597,000 | 0 | 0 | 0.1492 |
| 43 | TOTAL | 54,361,783 | 3,551,703,349 | 1,706,127 | 31,863 | 0.0653 |

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|---|---|---|---|---|---|---|
| 1 | 05LGSV046T-LRG GEN SERV | 8,471 | 437,668 | | | 0.0517 |
| 2 | 05LGSV048T-LRG GENSRV TIM | 3,234 | 251,523 | 1 | 3,234,000 | 0.0778 |
| 3 | 05LNX00100-LINE EXT 60% G | | 88 | | | |
| 4 | 05LNX00102-LINE EXT 80% G | | 758,828 | | | |
| 5 | 05LNX00103-LINE EXT 80% | | 808 | | | |
| 6 | 05LNX00105-CNTRCT $ MIN G | | 5,343 | | | |
| 7 | 05LNX00109-REF/NREF ADV | | 588,392 | | | |
| 8 | 05LNX00114-TEMP SVC 12MO> | | -4,827 | | | |
| 9 | 05NMT25135 - WY NET MTR, GEN, | 502 | 41,070 | 5 | 100,400 | 0.0818 |
| 10 | 05NMT25135 - WY NET MTR, GEN, | 3,025 | 471,170 | 1,795 | 1,685 | 0.1558 |
| 11 | 05RCFL0054-WY REC FIELD L | 737 | 60,476 | 52 | 14,173 | 0.0821 |
| 12 | 05RFNDCENT-CENTRALIA RFND | | 9 | | | |
| 13 | 09GNSV0025-GEN SVC-SINGLE | | 88 | 1 | | |
| 14 | 05LNX00300 - LINE EXT 80% | | 301,471 | | | |
| 15 | 05LNX00311 - LINE EXT 80% | | 33,922 | | | |
| 16 | ACQUISITION COMMITMENT-A and | | 28,526 | | | |
| 17 | ACQUISITION | | 22,018 | | | |
| 18 | SMUD REVENUE IMPUTATIONS | | 144,892 | | | |
| 19 | UNBILLED REVENUE | 20,020 | 1,708,000 | | | 0.0853 |
| 20 | 05GNSV0025-WY GEN | 90,669 | 6,374,770 | 1,729 | 52,440 | 0.0703 |
| 21 | 05GNSV025F-GEN SRVC-FL | 194 | 19,099 | 30 | 6,467 | 0.0984 |
| 22 | 05LNX00102-LINE EXT 80% G | | 5,325 | | | |
| 23 | 05LNX00109-REF/NREF ADV + | | 87,006 | | | |
| 24 | 05LNX00110-REF/NREF ADV + | | 1,963 | | | |
| 25 | 05LNX00114-TEMP SVC | | 167 | | | |
| 26 | 09GNSV0025-GEN SVC-SINGLE | 50,838 | 3,214,717 | 816 | 62,301 | 0.0632 |
| 27 | 09GNSV025F-GEN SVC-FIXED | 39 | 3,856 | 7 | 5,571 | 0.0989 |
| 28 | 09GNSV025M-GEN SVC-MANUAL | 2,196 | 144,986 | 1 | 2,196,000 | 0.0660 |
| 29 | 05NMT25135 - WY NET MTR, GEN, | 105 | 6,746 | 1 | 105,000 | 0.0642 |
| 30 | 09OALT207N-SECURITY AR LG | 266 | 70,671 | 144 | 1,847 | 0.2657 |
| 31 | 09SLCU2123-MTR OUTDONIGHT | 48 | 4,604 | 2 | 24,000 | 0.0959 |
| 32 | 05LNX00300 - LINE EXT 80% | | 5,526 | | | |
| 33 | 05LNX00311 - LINE EXT 80% | | 2,285 | | | |
| 34 | SMUD REVENUE IMPUTATIONS | | 9,229 | | | |
| 35 | LESS MULTIPLE BILLINGS | | | -25,582 | | |
| 36 | | | | | | |
| 37 | TOTAL COMMERCIAL SALES | 16,055,182 | 1,062,312,561 | 210,217 | 76,374 | 0.0662 |
| 38 | | | | | | |
| 39 | INDUSTRIAL SALES | | | | | |
| 40 | CALIFORNIA | | | | | |
| 41 | TOTAL Billed | 54,237,100 | 3,533,106,349 | 1,706,127 | 31,790 | 0.0651 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 124,683 | 18,597,000 | 0 | 0 | 0.1492 |
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|---|---|---|---|---|---|---|
| 1 | 06GNSV0025-CA GEN SRVC | 753 | 97,725 | 96 | 7,844 | 0.1298 |
| 2 | 06GNSV0A32-GEN SRVC-20 KW | 2,102 | 250,036 | 28 | 75,071 | 0.1190 |
| 3 | 06LGSV048T-LRG GEN SERV | 48,700 | 3,202,770 | 5 | 9,740,000 | 0.0658 |
| 4 | 06LGSV0A36-LRG GEN SRVC-O | 6,093 | 584,372 | 15 | 406,200 | 0.0959 |
| 5 | 06LNX00109-REF/NREF ADV + | | 1,554 | | | |
| 6 | ACQUISITION COMMITMENT-A and | | 3,935 | | | |
| 7 | ACQUISITION | | 2,457 | | | |
| 8 | SMUD REVENUE IMPUTATIONS | | 8,909 | | | |
| 9 | UNBILLED REVENUE | 11 | 27,000 | | | 2.4545 |
| 10 | IDAHO | | | | | |
| 11 | 07CFR00001-MTH FACILITY S | | 2,217 | | | |
| 12 | 07CISH0019-COMM & IND | 170 | 12,117 | 4 | 42,500 | 0.0713 |
| 13 | 07GNSV0006-GEN SRVC-LRG | 113,384 | 5,821,761 | 118 | 960,881 | 0.0513 |
| 14 | 07GNSV0008-GEN SRVC-MEDIU | 2,544 | 140,894 | 2 | 1,272,000 | 0.0554 |
| 15 | 07GNSV0009-GEN SRVC-HI VO | 77,126 | 3,462,000 | 11 | 7,011,455 | 0.0449 |
| 16 | 07GNSV0023-GEN SRVC-SML P | 11,367 | 874,253 | 353 | 32,201 | 0.0769 |
| 17 | 07GNSV0035-GEN SRVCOPTION | 1,610 | 89,879 | 1 | 1,610,000 | 0.0558 |
| 18 | 07GNSV006A-GEN SRVC-LRG P | 5,206 | 333,546 | 34 | 153,118 | 0.0641 |
| 19 | 07GNSV023A-GEN SRVC-SML P | 2,169 | 198,300 | 256 | 8,473 | 0.0914 |
| 20 | 07GNSV023A-GEN SRVC-SML P | | 1 | | | |
| 21 | 07GNSV023S-IDAHO TRAFFIC | 8 | 1,050 | 3 | 2,667 | 0.1313 |
| 22 | 07LNX00035-ADV 80%MO GUAR | | 1,507 | | | |
| 23 | 07LNX00108-ANN COST MTHLY | | 1,996 | | | |
| 24 | 07LNX00300 - 80% MONTHLY MIN | | 3,929 | | | |
| 25 | 07OALT007N-SECURITY AR LG | 12 | 4,573 | 16 | 750 | 0.3811 |
| 26 | 07OALT07AN-SECURITY AR LG | 2 | 847 | 3 | 667 | 0.4235 |
| 27 | 07SPCL0001 | 1,339,700 | 54,483,060 | 1 | 1,339,700,000 | 0.0407 |
| 28 | 07SPCL0002 | 107,895 | 4,188,089 | 1 | 107,895,000 | 0.0388 |
| 29 | ACQUISITION COMMITMENT-A and | | 137,908 | | | |
| 30 | ACQUISITION | | 133,815 | | | |
| 31 | BPA BALANCING ACCOUNT | | 195 | | | |
| 32 | SMUD REVENUE IMPUTATIONS | | -975,241 | | | |
| 33 | UNBILLED REVENUE | -18,486 | 51,000 | | | -0.0028 |
| 34 | OREGON | | | | | |
| 35 | 01COST0023, OR GEN SRV, COST | 22,320 | 923,325 | | | 0.0414 |
| 36 | 01COST0048 - 01LGSV0048 | 1,506,735 | 56,236,177 | | | 0.0373 |
| 37 | 01COST023F - OR GEN SRV - | 3 | 155 | | | 0.0517 |
| 38 | 01COSTB023 - OR GEN SRV, | 370 | 15,868 | | | 0.0429 |
| 39 | 01COSTL030 - OR LRG GEN SRV, | 225,523 | 8,968,212 | | | 0.0398 |
| 40 | 01COSTS028, OR GEN SERV, | 109,351 | 4,449,902 | | | 0.0407 |
| 41 | TOTAL Billed | 54,237,100 | 3,533,106,349 | 1,706,127 | 31,790 | 0.0651 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 124,683 | 18,597,000 | 0 | 0 | 0.1492 |
| 43 | TOTAL | 54,361,783 | 3,551,703,349 | 1,706,127 | 31,863 | 0.0653 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original (2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## SALES OF ELECTRICITY BY RATE SCHEDULES

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

| Line No. | Number and Title of Rate schedule (a) | MWh Sold (b) | Revenue (c) | Average Number of Customers (d) | KWh of Sales Per Customer (e) | Revenue Per KWh Sold (f) |
|---|---|---|---|---|---|---|
| 1 | 01GNSB0023 - BPA DISC, < 30 | | -136 | | | |
| 2 | 01GNSB0023, OR GEN SRV, BPA, | | 23,328 | 63 | | |
| 3 | 01GNSB0028 - OR GEN SRVC, | | -284 | | | |
| 4 | 01GNSB0028, OR GEN SRV, BPA, | | 21,828 | 6 | | |
| 5 | 01GNSV0023, OR GEN SRV, < 30 | | 877,482 | 1,159 | | |
| 6 | 01GNSV0028, OR GEN SRV > 30 | | 2,898,417 | 536 | | |
| 7 | 01GNSV023F - OR GEN SRV - | 1 | 754 | 3 | 333 | 0.7540 |
| 8 | 01GNSV023M - OR GEN SRV, | 4 | 898 | 1 | 4,000 | 0.2245 |
| 9 | 01GNSV023T, OR GEN SRV, TOU | | 3,169 | 4 | | |
| 10 | 01HABT0023, OR HABITAT | 11 | 502 | | | 0.0456 |
| 11 | 01LGSV0030 - OR LRG GEN SRV, | | 5,137,448 | 177 | | |
| 12 | 01LGSV0048-1000KW AND OVR | | 13,656,901 | 115 | | |
| 13 | 01LGSV048M-LRG GEN SRVC 1 | 522,563 | 21,400,133 | 5 | 104,512,600 | 0.0410 |
| 14 | 01LNX00102-LINE EXT 80% G | | 2,583 | | | |
| 15 | 01LNX00105-CNTRCT $ MIN | | 3,090 | | | |
| 16 | 01LNX00109-REF/NREF ADV | | 2,225 | | | |
| 17 | 01LNX00300 - LINE EXT 80% | | 12,514 | | | |
| 18 | 01LPRS047M-PART REQ | 573,261 | 23,387,391 | 4 | 143,315,250 | 0.0408 |
| 19 | 01NMT28135 - OR NET MTR, GEN, | | 7,438 | 2 | | |
| 20 | 01OALT014N-OUTD AR LGT NR | 5 | 610 | 5 | 1,000 | 0.1220 |
| 21 | 01OALT014N-OUTD AR LGT | | -2 | | | |
| 22 | 01OALT015N-OUTD AR LGT | 367 | 44,649 | 155 | 2,368 | 0.1217 |
| 23 | 01PTOU0023, OR GEN SRV, TOU | 68 | 2,845 | | | 0.0418 |
| 24 | 01RENW0023, OR RENW USAGE | 284 | 11,774 | | | 0.0415 |
| 25 | 01RENWB023 - OR RENEWABLE | 1 | 56 | | | 0.0560 |
| 26 | BPA BALANCING ACCOUNT | | -932 | | | |
| 27 | 01STDAY023 - OR DAY STD OFR, | 32 | 1,913 | | | 0.0598 |
| 28 | 01LGSV028M - OR LGSV, <1000 | 44 | 2,642 | 1 | 44,000 | 0.0600 |
| 29 | OR SB 408 RECOVERY | | 6,055,748 | | | |
| 30 | OR SB 838 RECOVERY | | 2,477,400 | | | |
| 31 | SMUD REVENUE IMPUTATIONS | | 423,017 | | | |
| 32 | UNBILLED REVENUE | -35,752 | -1,727,000 | | | 0.0483 |
| 33 | UTAH | | | | | |
| 34 | 08CFR00051-MTH FAC SRVCHG | | 16,329 | | | |
| 35 | 08EFOP0021-ELEC FURNACE O | 1,890 | 127,356 | 2 | 945,000 | 0.0674 |
| 36 | 08EFOP021M-ELEC FURNACE O | 1,455 | 144,440 | 3 | 485,000 | 0.0993 |
| 37 | 08GNSV0006-GEN SRVC-DISTR | 762,934 | 51,857,232 | 1,309 | 582,837 | 0.0680 |
| 38 | 08GNSV0009-GEN SRVC-HI VO | 2,459,783 | 99,732,184 | 111 | 22,160,207 | 0.0405 |
| 39 | 08GNSV0023-GEN SRVC-DISTR | 61,031 | 4,757,739 | 3,749 | 16,279 | 0.0780 |
| 40 | 08GNSV006A-GEN SRVC-ENERG | 47,102 | 4,569,197 | 245 | 192,253 | 0.0970 |
| 41 | TOTAL Billed | 54,237,100 | 3,533,106,349 | 1,706,127 | 31,790 | 0.0651 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 124,683 | 18,597,000 | 0 | 0 | 0.1492 |
| 43 | TOTAL | 54,361,783 | 3,551,703,349 | 1,706,127 | 31,863 | 0.0653 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

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

| Line No. | Number and Title of Rate schedule (a) | MWh Sold (b) | Revenue (c) | Average Number of Customers (d) | KWh of Sales Per Customer (e) | Revenue Per KWh Sold (f) |
|---|---|---|---|---|---|---|
| 1 | 08GNSV006B-GEN | 3,364 | 250,026 | 7 | 480,571 | 0.0743 |
| 2 | 08GNSV006M-MNL DIST VOLTG | 548 | 35,890 | 1 | 548,000 | 0.0655 |
| 3 | 08GNSV009A-GEN SRVC HI | 18,261 | 1,088,586 | 6 | 3,043,500 | 0.0596 |
| 4 | 08GNSV009M-MANL HIGH | 1,087,322 | 41,289,769 | 13 | 83,640,154 | 0.0380 |
| 5 | 08GNSV023F-GEN SRVC FIXED | 4 | 1,634 | 1 | 4,000 | 0.4085 |
| 6 | 08GNSV06MN-GNSV DIST VOLT | 1,224 | 81,231 | 30 | 40,800 | 0.0664 |
| 7 | 08GNSV09AM-MAN TOD HIVOLT | 1,158 | 104,996 | 1 | 1,158,000 | 0.0907 |
| 8 | 08LNX00002-MTHLY 80% GUAR | | 5,815 | | | |
| 9 | 08LNX00014-80% MIN | | 50,159 | | | |
| 10 | 08LNX00017-ADV/REF&80%ANN | | 3,612 | | | |
| 11 | 08LNX00311 - LINE EXT 80% | | 1,842 | | | |
| 12 | 08LNX00300 - LINE EXT 80% PLUS | | 5,745 | | | |
| 13 | 08LNX00310 - IRR, 80% ANNUAL | | 6,356 | | | |
| 14 | 08OALT007N-SECURITY AR | 1,509 | 296,995 | 534 | 2,826 | 0.1968 |
| 15 | 08PRSV031M-BKUP MNT&SUPPL | 50 | 26,611 | 1 | 50,000 | 0.5322 |
| 16 | 08TOSS0015-TRAF & OTHER S | 43 | 3,165 | 8 | 5,375 | 0.0736 |
| 17 | 08MONL0015-MTR OUTDONIGHT | 11 | 2,792 | 6 | 1,833 | 0.2538 |
| 18 | 08SPCL000108SPCL0001 | 566,942 | 22,311,173 | 1 | 566,942,000 | 0.0394 |
| 19 | 08SPCL0002 | 961,257 | 27,824,033 | 1 | 961,257,000 | 0.0289 |
| 20 | 08SPCL0003 | 673,340 | 23,196,530 | 1 | 673,340,000 | 0.0345 |
| 21 | 08SPCL0005 | 255,361 | 9,218,335 | 1 | 255,361,000 | 0.0361 |
| 22 | ACQUISITION | | 151,637 | | | |
| 23 | SMUD REVENUE IMPUTATIONS | | 733,438 | | | |
| 24 | 08GNSV06AM-MNL ENERGY TOD | 135 | 13,231 | 1 | 135,000 | 0.0980 |
| 25 | 08GNSV0008 - UT GEN SVC TOU > | 971,010 | 56,115,345 | 115 | 8,443,565 | 0.0578 |
| 26 | 08GNSV008M - UT GEN SVC TOU | 63,275 | 3,563,530 | 8 | 7,909,375 | 0.0563 |
| 27 | UNBILLED REVENUE | -25,601 | -277,000 | | | 0.0108 |
| 28 | WASHINGTON | | | | | |
| 29 | 02GNSB0024-WA GEN SRVC | 2,862 | 201,799 | 102 | 28,059 | 0.0705 |
| 30 | 02GNSB0024-WA GEN SRVC DO | | -559 | | | |
| 31 | 02GNSB24FP-WA GEN SVC | 13 | 2,166 | 1 | 13,000 | 0.1666 |
| 32 | 02GNSV0024-WA GEN SRVC | 16,477 | 1,122,489 | 366 | 45,019 | 0.0681 |
| 33 | 02GNSV024F-WA GEN | 33 | 6,276 | 4 | 8,250 | 0.1902 |
| 34 | 02LGSV0036-WA LRG GEN SRV | 133,664 | 7,679,003 | 128 | 1,044,250 | 0.0575 |
| 35 | 02LGSV048M-WA LRG GEN SRV | 26,414 | 1,698,933 | 1 | 26,414,000 | 0.0643 |
| 36 | 02LGSV048T-LRG GEN SRVC 1 | 690,523 | 31,041,808 | 33 | 20,924,939 | 0.0450 |
| 37 | 02OALT015N-WA OUTD AR LGT | 127 | 14,778 | 43 | 2,953 | 0.1164 |
| 38 | 02OALTB15N-WA OUTD AR LGT | 32 | 4,263 | 19 | 1,684 | 0.1332 |
| 39 | 02OALTB15N-WA OUTD AR LGT | | -8 | | | |
| 40 | 02PRSV47TM-LRG PART REQMT | 1,120 | 81,026 | 1 | 1,120,000 | 0.0723 |
| 41 | TOTAL Billed | 54,237,100 | 3,533,106,349 | 1,706,127 | 31,790 | 0.0651 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 124,683 | 18,597,000 | 0 | 0 | 0.1492 |
| 43 | TOTAL | 54,361,783 | 3,551,703,349 | 1,706,127 | 31,863 | 0.0653 |

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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 | 02LGSB0036-LRG GEN SVC IRG | 4,519 | 398,423 | 29 | 155,828 | 0.0882 |
| 2 | 02LGSB0036-LRG GENSVC IRG | | -619 | | | |
| 3 | ACQUISITION COMMITMENT-A and | | 129 | | | |
| 4 | BPA BALANCING ACCOUNT | | -991 | | | |
| 5 | SMUD REVENUE | | -441,720 | | | |
| 6 | UNBILLED REVENUE | -2,122 | -84,000 | | | 0.0396 |
| 7 | WYOMING | | | | | |
| 8 | 05GNSV0025-WY GEN SRVC | 298,979 | 18,461,835 | 1,641 | 182,193 | 0.0617 |
| 9 | 05GNSV025F-GEN SRVC-FL RA | 83 | 8,484 | 16 | 5,188 | 0.1022 |
| 10 | 05GNSV025M - General Service | 717 | 38,225 | 1 | 717,000 | 0.0533 |
| 11 | 05LGSV0046-WY LRG GEN | 1,240,884 | 61,669,869 | 56 | 22,158,643 | 0.0497 |
| 12 | 05LGSV046M-WY LRG GEN | 511,542 | 23,513,930 | 4 | 127,885,500 | 0.0460 |
| 13 | 05LGSV046T-LRG GEN SERV | 34,173 | 1,676,746 | | | 0.0491 |
| 14 | 05LGSV048M-TOU>1000KW MAN | 1,254,294 | 47,817,925 | 3 | 418,098,000 | 0.0381 |
| 15 | 05LGSV048T-LRG GENSRV TIM | 946,542 | 36,974,931 | 9 | 105,171,333 | 0.0391 |
| 16 | 05LNX00100-LINE EXT 60% G | | 18,309 | | | |
| 17 | 05LNX00102-LINE EXT 80% G | | 188,433 | | | |
| 18 | 05LNX00105-CNTRCT $ MIN G | | 42,176 | | | |
| 19 | 05LNX00109-REF/NREF ADV + | | 165,022 | | | |
| 20 | 05OALT015N-OUTD AR LGT SR | 89 | 12,783 | 47 | 1,894 | 0.1436 |
| 21 | 05PRSV033M-PART SERV REQ | 1,106,342 | 50,429,555 | 5 | 221,268,400 | 0.0456 |
| 22 | 09GNSV025M-GEN SVC-MANUAL | 115 | 7,176 | 1 | 115,000 | 0.0624 |
| 23 | ACQUISITION COMMITMENT-A and | | 127,504 | | | |
| 24 | ACQUISITION | | 98,417 | | | |
| 25 | SMUD REVENUE IMPUTATIONS | | 652,349 | | | |
| 26 | 05LNX00300 - LINE EXT 80% | | 2,909 | | | |
| 27 | UNBILLED REVENUE | 82,023 | 5,866,000 | | | 0.0715 |
| 28 | 05GNSV0025-WY GEN SRVC | 25,327 | 1,679,038 | 254 | 99,713 | 0.0663 |
| 29 | 05GNSV025M - General Service | 49 | 3,309 | 1 | 49,000 | 0.0675 |
| 30 | 05LGSV0046-WY LRG GEN SRV | 26,426 | 1,416,188 | 4 | 6,606,500 | 0.0536 |
| 31 | 05LGSV046T-LRG GEN SERV | 1,224 | 56,577 | | | 0.0462 |
| 32 | 05LGSV048M-TOU>1000KW MAN | 349,769 | 13,671,345 | 4 | 87,442,250 | 0.0391 |
| 33 | 05LGSV048T-LRG GENSRV | 808,934 | 34,823,514 | 11 | 73,539,455 | 0.0430 |
| 34 | 05LNX00102-LINE EXT 80% G | | 1,221,044 | | | |
| 35 | 05LNX00109-REF/NREF ADV | | -27 | | | |
| 36 | 05PRSV033M-PART SERV REQ | 9,820 | 517,963 | 1 | 9,820,000 | 0.0527 |
| 37 | 09GNSV0025-GEN | 12,332 | 787,095 | 301 | 40,970 | 0.0638 |
| 38 | 09GNSV025M-GEN SVC-MANUAL | 4,677 | 250,942 | 3 | 1,559,000 | 0.0537 |
| 39 | 09OALT207N-SECURITY AR | 5 | 1,130 | 3 | 1,667 | 0.2260 |
| 40 | 09PRSV033M09PRSV033M | 1,197 | 272,887 | 1 | 1,197,000 | 0.2280 |
| | | | | | | |
| 41 | TOTAL Billed | 54,237,100 | 3,533,106,349 | 1,706,127 | 31,790 | 0.0651 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 124,683 | 18,597,000 | 0 | 0 | 0.1492 |
| 43 | TOTAL | 54,361,783 | 3,551,703,349 | 1,706,127 | 31,863 | 0.0653 |

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|---|---|---|---|---|---|---|
| 1 | LESS MULTIPLE BILLINGS | | | -1,240 | | |
| 2 | | | | | | |
| 3 | TOTAL INDUSTRIAL SALES | 20,128,170 | 909,975,226 | 11,191 | 1,798,603 | 0.0452 |
| 4 | | | | | | |
| 5 | IRRIGATION SALES | | | | | |
| 6 | CALIFORNIA | | | | | |
| 7 | 06APSV0020-AG PMP SRVC | 69,210 | 6,686,379 | 1,347 | 51,381 | 0.0966 |
| 8 | 06LNX00102-LINE EXT 80% G | | 787 | | | |
| 9 | 06LNX00103-LINE EXT 80% G | | 1,921 | | | |
| 10 | 06LNX00110-REF/NREF ADV + | | 13,036 | | | |
| 11 | 06LNX00312 - CA IRG LINE EXT | | 2,377 | | | |
| 12 | 06USBR0040-KLAM IRG ONPRJ | 30,820 | 1,842,813 | 677 | 45,524 | 0.0598 |
| 13 | 06LNX00109-REF/NREF ADV + | | 195 | | | |
| 14 | IRRIGATION UNBILLED | -3 | -1,000 | | | 0.3333 |
| 15 | IDAHO | | | | | |
| 16 | 07APSA010L - IRG & Pump BPA | | -35,472 | | | |
| 17 | 07APSA010L - IRG & Pump Large | 485,956 | 33,272,601 | 3,227 | 150,591 | 0.0685 |
| 18 | 07APSA010S - IRG & Pump Small | 4,325 | 379,237 | 386 | 11,205 | 0.0877 |
| 19 | 07APSAL10X - IRG & PUMP - Large | 89,547 | 6,311,019 | 792 | 113,064 | 0.0705 |
| 20 | 07APSAS10X - IRG & PUMP - Small | 1,689 | 161,111 | 210 | 8,043 | 0.0954 |
| 21 | 07APSVCNLL-LRG LOAD CANAL | 34,047 | 2,100,092 | 88 | 386,898 | 0.0617 |
| 22 | 07APSVCNLS-SML LOAD CANAL | 264 | 21,188 | 18 | 14,667 | 0.0803 |
| 23 | 07BPADEBIT-BPA ADJUST FEE | | -1,384 | | | |
| 24 | 07LNX00015-ANNUAL 80%GUAR | | 5,036 | | | |
| 25 | 07LNX00040-ADV+REFCHG+80% | | 141,261 | | | |
| 26 | 07LNX00107-SUBD ADV & | | 1,087 | | | |
| 27 | 07LNX00310 80% ANNUAL | | 2,473 | | | |
| 28 | 07LNX00312 - ID LINE EXT | | 12,721 | | | |
| 29 | 07APSN010L - ID LG IRR & PUMP | 3,628 | 278,840 | 43 | 84,372 | 0.0769 |
| 30 | 07APSN010S - IRRIGATION, | 431 | 33,673 | 17 | 25,353 | 0.0781 |
| 31 | 07APSNS10X - IRRIGATION, | 46 | 4,363 | 2 | 23,000 | 0.0948 |
| 32 | IRRIGATION BPA BAL ACCT | | 299,366 | | | |
| 33 | OREGON | | | | | |
| 34 | 01APSV0041-AG PMP SRVC BP | | 1,937,134 | 4,754 | | |
| 35 | 01APSV0041-AG PMP SRVC BP | | -2,113 | | | |
| 36 | 01APSV041L-OR Pumping Serv | | 2,710,097 | 1,085 | | |
| 37 | 01APSV041L-OR Pumping Serv | | -3,650 | | | |
| 38 | 01APSV041T - AGR PUMP SRV | | -6 | | | |
| 39 | 01APSV041T - AGR PUMP | | 25,732 | 58 | | |
| 40 | 01APSV041X-AG PMP SRVC | | 79,401 | 236 | | |
| 41 | TOTAL Billed | 54,237,100 | 3,533,106,349 | 1,706,127 | 31,790 | 0.0651 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 124,683 | 18,597,000 | 0 | 0 | 0.1492 |
| 43 | TOTAL | 54,361,783 | 3,551,703,349 | 1,706,127 | 31,863 | 0.0653 |

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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 | 01APSV41XL-OR Pumping Serv no | | 135,157 | 45 | | |
| 2 | 01COST0041 | 133,591 | 5,427,953 | | | 0.0406 |
| 3 | 01COST0048 - 01LGSV0048 | 9,840 | 363,362 | | | 0.0369 |
| 4 | 01COSTS028, OR GEN SERV, | 282 | 11,531 | | | 0.0409 |
| 5 | 01GNSV0028, OR GEN SRV > 30 | | 8,466 | 2 | | |
| 6 | 01HABIT041 - 01APSV0041 AG | 3 | 134 | | | 0.0447 |
| 7 | 01LGSB0048 - LG GEN SVC > | | -230 | | | |
| 8 | 01LGSB0048 - LG GEN SVC > | | 74,149 | 1 | | |
| 9 | 01LNX00102-LINE EXT 80% G | | 169 | | | |
| 10 | 01LNX00103-LINE EXT 80% G | | 14,022 | | | |
| 11 | 01LNX00109-REF/NREF ADV + | | 671 | | | |
| 12 | 01LNX00110-REF/NREF ADV + | | 95,398 | | | |
| 13 | 01LNX00310-LINE EXTENSION | | 1,356 | | | |
| 14 | 01PTOU0041 - 01APSV0041 AG | 645 | 22,946 | | | 0.0356 |
| 15 | 01RENEW041 - 01APSV0041 AG | 134 | 5,441 | | | 0.0406 |
| 16 | 01SLX00005-KLAMATH FALLS | | 124,656 | | | |
| 17 | 01SLX00013-K FALLS IRG MI | | 7,685 | | | |
| 18 | 01SLX00014-K FALLS IRG MI | | 210 | | | |
| 19 | 01STDAY041 - Daily Standard Offer | 32 | 1,415 | | | 0.0442 |
| 20 | 01USBOF033-KLAMATH BASIN | 45,975 | 823,454 | 656 | 70,084 | 0.0179 |
| 21 | 01USBOF033-KLAMATH BASIN | | -61 | | | |
| 22 | 01USBON033-KLAMATH BASIN | 55,034 | 855,249 | 1,404 | 39,198 | 0.0155 |
| 23 | 01USBON033-KLAMATH BASIN | | -436 | | | |
| 24 | 01USBGV033-IRG TOU W/O BPA | 3,310 | 32,978 | 10 | 331,000 | 0.0100 |
| 25 | IRRIGATION BPA BAL ACCT | | -56,919 | | | |
| 26 | IRRIGATION UNBILLED | 42 | -8,000 | | | -0.1905 |
| 27 | 01LNX00312 - OR IRG LINE EXT | | 3,543 | | | |
| 28 | OR SB408 RECOVERY | | 500,825 | | | |
| 29 | OR SB 838 RECOVERY | | 88,133 | | | |
| 30 | UTAH | | | | | |
| 31 | 08APSV0010-IRR & SOIL DRA | 200,370 | 10,990,020 | 2,569 | 77,995 | 0.0548 |
| 32 | 08APSV10NS- Irg Soil Drain Pump N | 12,388 | 667,286 | 81 | 152,938 | 0.0539 |
| 33 | 08LNX00002-MTHLY 80% GUAR | | 884 | | | |
| 34 | 08LNX00004-ANNUAL 80%GUAR | | 34,938 | | | |
| 35 | 08LNX00014-80% MIN MNTHLY | | 1,550 | | | |
| 36 | 08LNX00017-ADV/REF&80%ANN | | 124,147 | | | |
| 37 | 08LNX00300 - LINE EXT 80% PLUS | | 227 | | | |
| 38 | 08LNX00310 - IRR, 80% ANNUAL | | 2,482 | | | |
| 39 | 08LNX00312 UT IRG LINE EXT | | 2,991 | | | |
| 40 | 08NMT10135-UT IRR_SOIL DRNG | 19 | 1,124 | 1 | 19,000 | 0.0592 |
| | | | | | | |
| 41 | TOTAL Billed | 54,237,100 | 3,533,106,349 | 1,706,127 | 31,790 | 0.0651 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 124,683 | 18,597,000 | 0 | 0 | 0.1492 |
| 43 | TOTAL | 54,361,783 | 3,551,703,349 | 1,706,127 | 31,863 | 0.0653 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
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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 | UNBILLED REV - IRRIGATION | -177 | -10,000 | | | 0.0565 |
| 2 | WASHINGTON | | | | | |
| 3 | 02APSV0040-WA AG PMP SRVC | 145,096 | 9,033,284 | 4,633 | 31,318 | 0.0623 |
| 4 | 02APSV0040-WA AG PMP SRVC | | -7,333 | | | |
| 5 | 02APSV040X-WA AG PMP SRVC | 21,479 | 1,337,083 | 647 | 33,198 | 0.0623 |
| 6 | 02LNX00102-LINE EXT 80% G | | 878 | | | |
| 7 | 02LNX00103-LINE EXT 80% G | | 4,452 | | | |
| 8 | 02LNX00105-CNTRCT $ MIN G | | 35 | | | |
| 9 | 02LNX00109-REF/NREF ADV + | | 1,676 | | | |
| 10 | 02LNX00110-REF/NREF ADV + | | 64,437 | | | |
| 11 | 02LNX00310 - IRG, 80% ANNUAL | | 124 | | | |
| 12 | 02LNX00312 - WA IRG LINE EXT | | 1,110 | | | |
| 13 | 02RFNDCENT - CENTRALIA RFND | | -7 | | | |
| 14 | 02ZZMERGCR-MERGER CREDITS | | -2 | | | |
| 15 | IRRIGATION BPA BAL ACCT | | -43,202 | | | |
| 16 | IRRIGATION UNBILLED | 3 | | | | |
| 17 | WYOMING | | | | | |
| 18 | 05APS00040-AG PUMPING SVC | 15,270 | 1,106,526 | 583 | 26,192 | 0.0725 |
| 19 | 05LNX00110-REF/NREF ADV + | | 49,160 | | | |
| 20 | 05LNX00103-LINE EXT 80% G | | 6,625 | | | |
| 21 | 05LNX00310-LINE EXTENSION | | 24 | | | |
| 22 | 05LNX00312 - WY IRG LINE EXT | | 135 | | | |
| 23 | 05LNX00103-LINE EXT 80% G | | 4,518 | | | |
| 24 | 05LNX00110-REF/NREF ADV + | | 15,850 | | | |
| 25 | 09APSV0210-IRR & SOIL DRA | 3,244 | 217,645 | 59 | 54,983 | 0.0671 |
| 26 | LESS MULTIPLE BILLINGS | | | -650 | | |
| 27 | | | | | | |
| 28 | TOTAL IRRIGATION SALES | 1,366,540 | 88,422,239 | 22,981 | 59,464 | 0.0647 |
| 29 | | | | | | |
| 30 | PUBLIC STREET&HIGHWAY | | | | | |
| 31 | CALIFORNIA | | | | | |
| 32 | 06COSL0052-CO-OWND STR LG | 8 | 6,365 | 5 | 1,600 | 0.7956 |
| 33 | 06CUSL053F-SPECIAL CUST O | 1,653 | 190,727 | 120 | 13,775 | 0.1154 |
| 34 | 06CUSL058F-CUST OWND STR | 243 | 32,254 | 23 | 10,565 | 0.1327 |
| 35 | 06HPSV0051-HI PRESSURE SO | 673 | 155,210 | 73 | 9,219 | 0.2306 |
| 36 | UNBILLED REVENUE | -1 | | | | |
| 37 | IDAHO | | | | | |
| 38 | 07GNSV023S-IDAHO TRAFFIC | 161 | 15,656 | 25 | 6,440 | 0.0972 |
| 39 | 07SLCO0011-STR LGT CO-OWN | 127 | 52,843 | 32 | 3,969 | 0.4161 |
| 40 | 07SLCU012E-ENGY STR | 14 | 2,241 | 3 | 4,667 | 0.1601 |
| 41 | TOTAL Billed | 54,237,100 | 3,533,106,349 | 1,706,127 | 31,790 | 0.0651 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 124,683 | 18,597,000 | 0 | 0 | 0.1492 |
| 43 | TOTAL | 54,361,783 | 3,551,703,349 | 1,706,127 | 31,863 | 0.0653 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
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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 | 07SLCU012F-FULL MNT STR | 1,896 | 349,865 | 276 | 6,870 | 0.1845 |
| 2 | 07SLCU012P-PART MNT STR LGT | 202 | 26,637 | 16 | 12,625 | 0.1319 |
| 3 | UNBILLED REVENUE | 89 | 20,000 | | | 0.2247 |
| 4 | OREGON | | | | | |
| 5 | 01COSL0052-STR LGT SRVC C | 1,170 | 136,352 | 68 | 17,206 | 0.1165 |
| 6 | 01CUSL0053-CUS-OWNED MTRD | 712 | 48,306 | 66 | 10,788 | 0.0678 |
| 7 | 01CUSL053E-STR LGT SVC | 8,173 | 555,001 | 165 | 49,533 | 0.0679 |
| 8 | 01CUSL053F-STR LGT SRVC C | 289 | 29,830 | 22 | 13,136 | 0.1032 |
| 9 | 01HPSV0051-HI PRESSURE SO | 16,958 | 3,210,860 | 675 | 25,123 | 0.1893 |
| 10 | 01MVSL0050-MERC VAPSTR LG | 10,923 | 1,288,716 | 276 | 39,576 | 0.1180 |
| 11 | 01OALT014N-OUTD AR LGT NR | 1 | 296 | 2 | 500 | 0.2960 |
| 12 | 01OALT014N-OUTD AR LGT NR | | -1 | | | |
| 13 | 01OALT015N-OUTD AR LGT NR | 9 | 1,244 | 4 | 2,250 | 0.1382 |
| 14 | OR SB408 RECOVERY | | 71,445 | | | |
| 15 | OR SB 838 RECOVERY | | 21,496 | | | |
| 16 | UNBILLED REVENUE | -267 | -40,000 | | | 0.1498 |
| 17 | UTAH | | | | | |
| 18 | 08CFR00012-STR LGTS (CONV | | 54 | | | |
| 19 | 08CFR00051-MTH FAC SRVCHG | | 4,529 | | | |
| 20 | 08CFR00061-U/G AREA LIGHT | | 127 | | | |
| 21 | 08CFR00062-STREET LIGHTS | | 79 | | | |
| 22 | 08HAXT0060-LIGHTNG-HAXTON | | 93 | 1 | | |
| 23 | 08OALT007N-SECURITY AR LG | 4 | 1,351 | 4 | 1,000 | 0.3378 |
| 24 | 08TOSS015F-TRAFFIC SIG NM | 1,309 | 92,091 | 131 | 9,992 | 0.0704 |
| 25 | 08SLCO0011-STR LGT CO-OWN | 23,313 | 6,422,012 | 1,075 | 21,687 | 0.2755 |
| 26 | 08TOSS0015-TRAF & OTHER S | 3,075 | 273,992 | 1,547 | 1,988 | 0.0891 |
| 27 | 08MONL0015-MTR OUTDONIGHT | 1,064 | 79,290 | 53 | 20,075 | 0.0745 |
| 28 | 08SLCU012P-STR LGT CUST-O | 5,643 | 631,562 | 211 | 26,744 | 0.1119 |
| 29 | 08SLCU012F-STR LGT CUST-O | 3,406 | 431,605 | 159 | 21,421 | 0.1267 |
| 30 | 08SLD13ES1-DECOR CUST-OWN | 5,703 | 347,612 | 80 | 71,288 | 0.0610 |
| 31 | 08SLCU012E-DECOR CUST-OWN | 31,649 | 1,960,872 | 277 | 114,256 | 0.0620 |
| 32 | 08SLD13FS1-DECOR COMP-OWN | 146 | 78,273 | 8 | 18,250 | 0.5361 |
| 33 | 08SLD13FS2-DECOR COMP-OWN | 178 | 112,352 | 12 | 14,833 | 0.6312 |
| 34 | 08SLD13MS1-DECOR CUST-OWN | 521 | 72,043 | 20 | 26,050 | 0.1383 |
| 35 | 08SLD13MS2-DECOR CUST-OWN | 694 | 106,397 | 22 | 31,545 | 0.1533 |
| 36 | 08THIK0077-STR LIGHT SPEC | 141 | 17,277 | 1 | 141,000 | 0.1225 |
| 37 | UNBILLED REVENUE | -195 | -26,000 | | | 0.1333 |
| 38 | WASHINGTON | | | | | |
| 39 | 02CFR00012-STR LGTS (CONV | | 91 | | | |
| 40 | 02COSL0052-WA STR LGT SRV | 452 | 59,578 | 19 | 23,789 | 0.1318 |
| 41 | TOTAL Billed | 54,237,100 | 3,533,106,349 | 1,706,127 | 31,790 | 0.0651 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 124,683 | 18,597,000 | 0 | 0 | 0.1492 |
| 43 | TOTAL | 54,361,783 | 3,551,703,349 | 1,706,127 | 31,863 | 0.0653 |

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|---|---|---|---|---|---|---|
| 1 | 02CUSL053F-WA STR LGT SRV | 3,494 | 221,220 | 118 | 29,610 | 0.0633 |
| 2 | 02CUSL053M-WA STR LGT SRV | 1,082 | 67,797 | 90 | 12,022 | 0.0627 |
| 3 | 02HPSV0051-WA HI PRESSURE | 3,024 | 546,193 | 144 | 21,000 | 0.1806 |
| 4 | 02MVSL0057-WA MERC VAPSTR | 2,054 | 227,970 | 47 | 43,702 | 0.1110 |
| 5 | UNBILLED REVENUE | -30 | -4,000 | | | 0.1333 |
| 6 | WYOMING | | | | | |
| 7 | 05COSL0057-CO-OWND STR LG | 443 | 91,202 | 25 | 17,720 | 0.2059 |
| 8 | 05CUSL058F-CUST OWND STR | 1,162 | 77,464 | 37 | 31,405 | 0.0667 |
| 9 | 05CUSL058M-CUST OWND STR | 74 | 4,839 | 10 | 7,400 | 0.0654 |
| 10 | 05HPSV0051-HI PRESSURE SO | 4,420 | 982,448 | 159 | 27,799 | 0.2223 |
| 11 | 05MVS00053-MERCURY VAPOR | 4,052 | 535,723 | 274 | 14,788 | 0.1322 |
| 12 | UNBILLED REVENUE | -223 | -99,000 | | | 0.4439 |
| 13 | 09SLCO0211-STR LGT CO-OWN | 1,287 | 357,975 | 79 | 16,291 | 0.2781 |
| 14 | 09SLCU2121-STR LGT CUST-O | 87 | 12,395 | 13 | 6,692 | 0.1425 |
| 15 | 09SLCU2122-TRAF & OTHER S | 60 | 2,745 | 14 | 4,286 | 0.0458 |
| 16 | LESS MULTIPLE BILLINGS | | | -2,401 | | |
| 17 | | | | | | |
| 18 | TOTAL PUBLIC STREET & | 141,122 | 19,865,594 | 4,080 | 34,589 | 0.1408 |
| 19 | | | | | | |
| 20 | OTHER SALES TO PUBLIC AUTH | | | | | |
| 21 | UTAH | | | | | |
| 22 | 08GNSV0006-GEN SRVC-DISTR | 2,328 | 147,632 | 4 | 582,000 | 0.0634 |
| 23 | 08GNSV0023-GEN SRVC-DISTR | 28 | 2,610 | 3 | 9,333 | 0.0932 |
| 24 | 08GNSV009M-MANL HIGH VOLT | 438,494 | 17,940,369 | 4 | 109,623,500 | 0.0409 |
| 25 | 08OALT007N-SECURITY AR LG | 18 | 4,294 | 2 | 9,000 | 0.2386 |
| 26 | UNBILLED REVENUE | 8,446 | 349,000 | | | 0.0413 |
| 27 | | | | | | |
| 28 | TOTAL OTHER SALES TO PUBLIC | 449,314 | 18,443,905 | 13 | 34,562,615 | 0.0410 |
| 29 | | | | | | |
| 30 | FORFEITED DISCOUNTS | | | | | |
| 31 | CALIFORNIA | | | | | |
| 32 | Late Fees | | 237,577 | | | |
| 33 | IDAHO | | | | | |
| 34 | Late Fees | | 458,710 | | | |
| 35 | OREGON | | | | | |
| 36 | Late Fees | | 2,772,734 | | | |
| 37 | UTAH | | | | | |
| 38 | Late Fees | | 2,900,775 | | | |
| 39 | WASHINGTON | | | | | |
| 40 | Late Fees | | 506,069 | | | |
| 41 | TOTAL Billed | 54,237,100 | 3,533,106,349 | 1,706,127 | 31,790 | 0.0651 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 124,683 | 18,597,000 | 0 | 0 | 0.1492 |
| 43 | TOTAL | 54,361,783 | 3,551,703,349 | 1,706,127 | 31,863 | 0.0653 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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|---|---|---|---|---|---|---|
| 1 | WYOMING | | | | | |
| 2 | Late Fees | | 610,871 | | | |
| 3 | | | | | | |
| 4 | TOTAL FORFEITED DISCOUNTS | | 7,486,736 | | | |
| 5 | | | | | | |
| 6 | MISCELLANEOUS SERVICE REV | | | | | |
| 7 | CALIFORNIA | | | | | |
| 8 | 06CFR00003-MTH MAINTENANC | | 1,454 | | | |
| 9 | 06CONN0300-CA RECONNECTIO | | 110,165 | | | |
| 10 | 06FCBUYOUT | | 5,247 | | | |
| 11 | 06RCHK0300-CA RET CHK CHR | | 14,387 | | | |
| 12 | 06TAMP0300-CA TAMP & UNAU | | 2,625 | | | |
| 13 | 06TEMP0300-CA TEMP SRVC C | | 5,385 | | | |
| 14 | 06TRBL0300-CA TROUBLE CAL | | 180 | | | |
| 15 | 06XMTRTAMP-TAMPERING - | | 849 | | | |
| 16 | Home Comfort | | 1,214 | | | |
| 17 | Other | | 12 | | | |
| 18 | IDAHO | | | | | |
| 19 | 07CFR00001-MTH FAC SRVCHG | | 1,892 | | | |
| 20 | 07CONN0300-ID RECONNECTIO | | 88,140 | | | |
| 21 | 07FCBUYOUT - FAC CHG BUYOUT | | 21,091 | | | |
| 22 | 07RCHK0300-ID RET CHK CHR | | 33,020 | | | |
| 23 | 07TAMP0300 | | 1,350 | | | |
| 24 | 07TEMP0014-TEMP SRVC CONN | | 14,310 | | | |
| 25 | 07XMTRTAMP-TAMPERING - | | 92 | | | |
| 26 | Weatherization Loans ID | | 1,695 | | | |
| 27 | Other | | -2,070 | | | |
| 28 | OREGON | | | | | |
| 29 | 01CFR00001-MTH FACILITY S | | 61,727 | | | |
| 30 | 01CFR00003-MTH MAINTENANC | | 26,017 | | | |
| 31 | 01CFR00004-EMRGNCY ST&BY | | 24,469 | | | |
| 32 | 01CFR00005-INTERMTNT | | 41,854 | | | |
| 33 | 01CFR00013-MTH MISC CHRG | | 2,284 | | | |
| 34 | 01CFR00014-YR MISC CHRG | | 5 | | | |
| 35 | 01CONN0300-RECONNECTION C | | 1,153,785 | | | |
| 36 | 01ESSC0600 - ESS charges | | 1,380 | | | |
| 37 | 01FCBUYOUT-FAC CHG BUYOUT | | 307,985 | | | |
| 38 | 01MTRVR300-METR VERIF FEE | | 300 | | | |
| 39 | 01RCHK0300-RETURNED CHECK | | 293,440 | | | |
| 40 | 01TAMP0300-TAMP & UNAUTH | | 18,300 | | | |
| | | | | | | |
| 41 | TOTAL Billed | 54,237,100 | 3,533,106,349 | 1,706,127 | 31,790 | 0.0651 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 124,683 | 18,597,000 | 0 | 0 | 0.1492 |
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|---|---|---|---|---|---|---|
| 1 | 01TEMP0300-TEMP SRVC CHRG | | 122,210 | | | |
| 2 | 01XMTRTAMP-TAMPERING - | | 5,298 | | | |
| 3 | Other | | 11,660 | | | |
| 4 | UTAH | | | | | |
| 5 | 08CFR00013-MTH MISC CHRG | | 147,885 | | | |
| 6 | 08CFR00051-MTH FAC SRVCHG | | 173,883 | | | |
| 7 | 08CFR00052-ANN FAC SVCCHG | | 424 | | | |
| 8 | 08CFR00053-MTHLY MAINTFEE | | 9,807 | | | |
| 9 | 08CFR00063-MTH MISC CHARG | | 3,316 | | | |
| 10 | 08CFR00064-ANN MISC CHARG | | 6,660 | | | |
| 11 | 08CONN0300-RECONN&DISCONN | | 384,380 | | | |
| 12 | 08CONTSERV-3RD PARTY O/S | | 209,209 | | | |
| 13 | 08FCBUYOUT-FAC CHG BUYOUT | | 288,061 | | | |
| 14 | 08SRVCHARG-EXCESS FOOTAGE | | 45 | | | |
| 15 | 08MTRVR300 - Meter Verification F | | -30 | | | |
| 16 | 08NCON0300-UT FEE NRES RE | | 4,415 | | | |
| 17 | 08RCHK0300-UT RET CHK CHR | | 410,650 | | | |
| 18 | 08RCON0001-CONNECT FEE | | 1,496,600 | | | |
| 19 | 08TAMP0300-TAMPERING&UNAU | | 21,075 | | | |
| 20 | 08TEMP0014-TEMP SRVC CONN | | 334,625 | | | |
| 21 | 08XMTRTAMP-TAMPERING - | | 1,333 | | | |
| 22 | Energy Finanswer 12,000 | | 1,200 | | | |
| 23 | Energy Finanswer new Com | | 49,647 | | | |
| 24 | Other | | -23,447 | | | |
| 25 | 08VISIT300 - UT Visit, Service Ca | | 275,170 | | | |
| 26 | Retrofit Finanswer | | 72 | | | |
| 27 | WASHINGTON | | | | | |
| 28 | 02CFR00003-MTH MAINTENANC | | 1,320 | | | |
| 29 | 02CFR00004-EMRGNCY ST&BY | | 5,884 | | | |
| 30 | 02CFR00005-INTERMTNT SRVC | | 4,302 | | | |
| 31 | 02CONN0300-WA RECONNECTIO | | 143,855 | | | |
| 32 | 02FCBUYOUT - FAC CHG BUYOUT | | 15,628 | | | |
| 33 | 02RCHK0300-WA RET CHK CHR | | 55,945 | | | |
| 34 | 02SRVCHARG-EXCESS FOOTAGE | | -483 | | | |
| 35 | 02TAMP0300-WA TAMP & UNAU | | 8,100 | | | |
| 36 | 02TEMP0300-WA TEMP SRVC C | | 30,490 | | | |
| 37 | 02XMTRTAMP-TAMPERING - | | 2,905 | | | |
| 38 | Energy Finanswer new Com | | 5,662 | | | |
| 39 | Home Comfort | | 5,751 | | | |
| 40 | Other | | -11,818 | | | |
| 41 | TOTAL Billed | 54,237,100 | 3,533,106,349 | 1,706,127 | 31,790 | 0.0651 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 124,683 | 18,597,000 | 0 | 0 | 0.1492 |
| 43 | TOTAL | 54,361,783 | 3,551,703,349 | 1,706,127 | 31,863 | 0.0653 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## SALES OF ELECTRICITY BY RATE SCHEDULES

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

| Line No. | Number and Title of Rate schedule (a) | MWh Sold (b) | Revenue (c) | Average Number of Customers (d) | KWh of Sales Per Customer (e) | Revenue Per KWh Sold (f) |
|---|---|---|---|---|---|---|
| 1 | WYOMING | | | | | |
| 2 | 05CFR00003-MTH MAINTENANC | | 8,032 | | | |
| 3 | 05CFR00004-EMRGNCY ST&BY | | 20,575 | | | |
| 4 | 05CFR00005-INTERMTNT SRVC | | 10,553 | | | |
| 5 | 05CFR00013-MTH MISC CHRG | | 3,186 | | | |
| 6 | 05CONN0300-WY RECONNECTIO | | 103,870 | | | |
| 7 | 05FCBUYOUT - FAC CHG BUYOUT | | 109,282 | | | |
| 8 | 05RCHK0300-WY RET CHK CHR | | 54,030 | | | |
| 9 | 05SERV0300-WY SRVC CALLS | | 5,880 | | | |
| 10 | 05TAMP0300 | | 825 | | | |
| 11 | 05TEMP0300-WY TEMP SRVC C | | 34,825 | | | |
| 12 | 05XMTRTAMP-TAMPERING - | | 46 | | | |
| 13 | 09CFR00005-INTERMTNT SRVC | | 339 | | | |
| 14 | 05CONN0300-WY RECONNECTIO | | 19,860 | | | |
| 15 | 05FCBUYOUT - FAC CHG BUYOUT | | 248,714 | | | |
| 16 | 05RCHK0300-WY RET CHK CHR | | 7,860 | | | |
| 17 | 05TAMP0300 | | 75 | | | |
| 18 | 05XMTRTAMP-TAMPERING - | | 5 | | | |
| 19 | 05TEMP0300-WY TEMP SRVC C | | 4,250 | | | |
| 20 | 09CFR00001-MTH FAC SRVCHG | | 4,731 | | | |
| 21 | 09CFR00014-YR MISC CHRG | | 3 | | | |
| 22 | Energy Finanswer 12,000 | | 432 | | | |
| 23 | Other | | 8,124 | | | |
| 24 | | | | | | |
| 25 | TOTAL MISC SERVICE REV | | 7,079,770 | | | |
| 26 | | | | | | |
| 27 | SALES OF WATER AND WTR PWR | | | | | |
| 28 | UTAH | | 26,406 | | | |
| 29 | TOTAL WATER AND WATER PWR | | 26,406 | | | |
| 30 | | | | | | |
| 31 | RENT FROM ELEC PROPERTIES | | | | | |
| 32 | CALIFORNIA | | | | | |
| 33 | 06CFR00006-MTH RNTAL CHRG | | 1,710 | | | |
| 34 | RENT REV-TRANSMISS | | 110 | | | |
| 35 | Rent Revenue - Subleases | | 16,338 | | | |
| 36 | Joint use | | 790,780 | | | |
| 37 | IDAHO | | | | | |
| 38 | 07CFR00009-YR LSE CHRG-EQ | | 794 | | | |
| 39 | 07INVCHG00-INVEST MNT CHG | | 181 | | | |
| 40 | 07LOOP0014-MTH FEE PRE-AS | | 2,344 | | | |
| | | | | | | |
| 41 | TOTAL Billed | 54,237,100 | 3,533,106,349 | 1,706,127 | 31,790 | 0.0651 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 124,683 | 18,597,000 | 0 | 0 | 0.1492 |
| 43 | TOTAL | 54,361,783 | 3,551,703,349 | 1,706,127 | 31,863 | 0.0653 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## SALES OF ELECTRICITY BY RATE SCHEDULES

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

| Line No. | Number and Title of Rate schedule (a) | MWh Sold (b) | Revenue (c) | Average Number of Customers (d) | KWh of Sales Per Customer (e) | Revenue Per KWh Sold (f) |
|---|---|---|---|---|---|---|
| 1 | 07POLE0075-STEEL POLES US | | 274 | | | |
| 2 | 07XTRN0013-RNT/LSE L& PRO | | 103,108 | | | |
| 3 | RENT REVENUE-HYDRO | | 13,084 | | | |
| 4 | RENT REV-DISTRIBUT | | 500 | | | |
| 5 | Rent Revenue - Subleases | | 2,216 | | | |
| 6 | Joint use | | 203,562 | | | |
| 7 | OREGON | | | | | |
| 8 | 01CFR00006-MTH RNTAL CHRG | | 534,291 | | | |
| 9 | 01XTRN0013-RNT/LSE L& PRO | | 29,140 | | | |
| 10 | RENTS - COMMON | | 434,257 | | | |
| 11 | Rents - Non Common | | 25 | | | |
| 12 | MCI FOGWIRE REVENUE | | 3,348,850 | | | |
| 13 | Rent Revenue - Subleases | | 449,218 | | | |
| 14 | RENT REVENUE-HYDRO | | 52,986 | | | |
| 15 | RENT REV-TRANSMISS | | 218,649 | | | |
| 16 | RENT REV-DISTRIBUT | | 16,463 | | | |
| 17 | RENT REV-GEN(COMM) | | 35,185 | | | |
| 18 | Joint use | | 4,405,108 | | | |
| 19 | UTAH | | | | | |
| 20 | 08CFR00056-MTH EQUIP RENT | | 33 | | | |
| 21 | 08CFR00058-MTH EQUIP LEAS | | 748,221 | | | |
| 22 | 08INVCHG0N-INVEST MNT CHG | | 4,839 | | | |
| 23 | 08INVCHG0R-INVEST MNT CHG | | 312 | | | |
| 24 | 08LOOP014N-TEMP SERV CONN | | 14,274 | | | |
| 25 | 08POLE0004-POLE ATTACHMEN | | 4,841 | | | |
| 26 | 08POLE0075-STEEL POLES US | | 64,736 | | | |
| 27 | 08XTRN0013-RNT/LSE L& PRO | | 75,184 | | | |
| 28 | RENTS - COMMON | | -16,242 | | | |
| 29 | Rents - Non Common | | 19,057 | | | |
| 30 | RENT REVENUE-STEAM | | 105,215 | | | |
| 31 | RENT REVENUE-HYDRO | | 121,500 | | | |
| 32 | RENT REV-TRANSMISS | | 883,999 | | | |
| 33 | RENT REV-DISTRIBUT | | 161,241 | | | |
| 34 | RENT REV-GEN(COMM) | | 566,277 | | | |
| 35 | Rent Revenue - Subleases | | 2,174,588 | | | |
| 36 | Joint use | | 2,201,262 | | | |
| 37 | WASHINGTON | | | | | |
| 38 | 02CFR00001-MTH FACILITY S | | 2,104 | | | |
| 39 | 02CFR00006-MTH RNTAL CHRG | | 34,538 | | | |
| 40 | Rents - Non Common | | 600 | | | |
| | | | | | | |
| 41 | TOTAL Billed | 54,237,100 | 3,533,106,349 | 1,706,127 | 31,790 | 0.0651 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 124,683 | 18,597,000 | 0 | 0 | 0.1492 |
| 43 | TOTAL | 54,361,783 | 3,551,703,349 | 1,706,127 | 31,863 | 0.0653 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## SALES OF ELECTRICITY BY RATE SCHEDULES

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

| Line No. | Number and Title of Rate schedule (a) | MWh Sold (b) | Revenue (c) | Average Number of Customers (d) | KWh of Sales Per Customer (e) | Revenue Per KWh Sold (f) |
|---|---|---|---|---|---|---|
| 1 | RENT REVENUE-HYDRORENT | | 612,639 | | | |
| 2 | RENT REV-DISTRIBUT | | 14,637 | | | |
| 3 | RENT REV-GEN(COMM) | | 37,803 | | | |
| 4 | RENT REV-TRANSMISS | | 1,450 | | | |
| 5 | Rent Revenue - Subleases | | 41,904 | | | |
| 6 | Joint use | | 1,545,027 | | | |
| 7 | WYOMING | | | | | |
| 8 | 05CFR00001-MTH FACILITY S | | 11,524 | | | |
| 9 | 05CFR00006-MTH RNTAL CHRG | | 2,944 | | | |
| 10 | Rents - Non Common | | 1,550 | | | |
| 11 | RENT REVENUE-STEAM | | 57,064 | | | |
| 12 | RENT REV-TRANSMISS | | 5,101 | | | |
| 13 | RENT REV-GEN(COMM) | | 7,224 | | | |
| 14 | Rent Revenue - Subleases | | 44,952 | | | |
| 15 | Joint use | | 348,356 | | | |
| 16 | 09LOOP0214-MTH FEE PRE-AS | | 180 | | | |
| 17 | 09POLE0075-STEEL POLES US | | 21,318 | | | |
| 18 | | | | | | |
| 19 | TOTAL RENT FROM ELEC PROP | | 20,579,425 | | | |
| 20 | | | | | | |
| 21 | OTHER ELECTRIC | | | | | |
| 22 | GENERAL OFFICE | | | | | |
| 23 | OTH ELEC ESTIMATE | | 590,791 | | | |
| 24 | GREEN CREDIT SALES | | 6,151,676 | | | |
| 25 | NON-WHEELING SYSTEM | | 10,659,957 | | | |
| 26 | Other Elec (exclud Wheel) | | 7,679,718 | | | |
| 27 | CALIFORNIA | | | | | |
| 28 | DSM REV-CA SBC OFF | | -752,367 | | | |
| 29 | Fish, Wildlife, Recr | | 3,707 | | | |
| 30 | IDAHO | | | | | |
| 31 | DSM REV-ID SBC | | 4,287,060 | | | |
| 32 | Other Elec (exclud Wheel) | | 316 | | | |
| 33 | 08XTRN0011-SALE ORDERS (I | | 650 | | | |
| 34 | OREGON | | | | | |
| 35 | 3RD PARTY TRANS | | 689,995 | | | |
| 36 | DSM REVENUE - OREGON ECC | | 6,830,798 | | | |
| 37 | Other Elec (exclud Wheel) | | 2,977,604 | | | |
| 38 | Other Elec DSR carry chrg | | 801,795 | | | |
| 39 | M&S INVENTORY REVENUE | | 2,594 | | | |
| 40 | 08XTRN0011-SALE ORDERS (I | | 326 | | | |
| | | | | | | |
| 41 | TOTAL Billed | 54,237,100 | 3,533,106,349 | 1,706,127 | 31,790 | 0.0651 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 124,683 | 18,597,000 | 0 | 0 | 0.1492 |
| 43 | TOTAL | 54,361,783 | 3,551,703,349 | 1,706,127 | 31,863 | 0.0653 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

| Line No. | Number and Title of Rate schedule (a) | MWh Sold (b) | Revenue (c) | Average Number of Customers (d) | KWh of Sales Per Customer (e) | Revenue Per KWh Sold (f) |
|---|---|---|---|---|---|---|
| 1 | JOINT USE REVENUE | | -5,637 | | | |
| 2 | UTAH | | | | | |
| 3 | ELEC INC-OTHR | | 240,280 | | | |
| 4 | FLYASH SALES | | 3,397,901 | | | |
| 5 | DSM REV-UT SBC OFFSET | | 26,180,373 | | | |
| 6 | 8XTRN0011-SALE ORDERS | | 1,336 | | | |
| 7 | M&S INVENTORY REVENUE | | 968,970 | | | |
| 8 | Fish, Wildlife, Recr | | 1,765 | | | |
| 9 | Other Elec (exclud Wheel) | | 2,778 | | | |
| 10 | WASHINGTON | | | | | |
| 11 | Fish, Wildlife, Recr | | 3,611 | | | |
| 12 | Wash Colstrip 3 | | -52,188 | | | |
| 13 | WYOMING | | | | | |
| 14 | FLYASH SALES | | 1,621,634 | | | |
| 15 | WY Regulatory Recovery Fee | | 205,820 | | | |
| 16 | Other Elec (exclud Wheel) | | 6,561 | | | |
| 17 | | | | | | |
| 18 | TOTAL OTHER ELEC REVENUE | | 72,497,824 | | | |
| 19 | | | | | | |
| 20 | | | | | | |
| 21 | | | | | | |
| 22 | | | | | | |
| 23 | | | | | | |
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| 36 | | | | | | |
| 37 | | | | | | |
| 38 | | | | | | |
| 39 | | | | | | |
| 40 | | | | | | |
| 41 | TOTAL Billed | 54,237,100 | 3,533,106,349 | 1,706,127 | 31,790 | 0.0651 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 124,683 | 18,597,000 | 0 | 0 | 0.1492 |
| 43 | TOTAL | 54,361,783 | 3,551,703,349 | 1,706,127 | 31,863 | 0.0653 |

***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)

## SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity ( i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

| Line No. | Name of Company or Public Authority (Footnote Affiliations) | Statistical Classifi-cation | 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 | Requirement Sales | | | | | |
| 2 | Brigham City | RQ | T-12 | 22 | 21 | 20 |
| 3 | Brigham City | RQ | T-6 | 17 | 16 | 15 |
| 4 | Deaver, Town of | RQ | T-4 | 0.2 | 0.1 | 0.1 |
| 5 | Helper City | RQ | T-6 | 0.8 | 1 | 0.9 |
| 6 | Helper City Annex | RQ | T-6 | 0.7 | 0.6 | 0.6 |
| 7 | Navajo Tribal Util Auth (Mexican Hat) | RQ | T-6 | 0.2 | 0.2 | 0.1 |
| 8 | Navajo Tribal Util Auth (Red Mesa) | RQ | T-6 | 1 | 1 | 1 |
| 9 | Portland General Electric Co. | RQ | 147 | NA | NA | NA |
| 10 | Price City | RQ | T-12 | 14 | 13 | 13 |
| 11 | Price City | RQ | T-6 | 12 | 12 | 11 |
| 12 | Accrual True-up | RQ | NA | NA | NA | NA |
| 13 | | | | | | |
| 14 | | | | | | |
| | Subtotal RQ | | | 0 | 0 | 0 |
| | Subtotal non-RQ | | | 0 | 0 | 0 |
| | **Total** | | | **0** | **0** | **0** |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## SALES FOR RESALE (Account 447) (Continued)

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

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

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

| MegaWatt Hours Sold (g) | REVENUE Demand Charges ($) (h) | Energy Charges ($) (i) | Other Charges ($) (j) | Total ($) (h+i+j) (k) | Line No. |
|---|---|---|---|---|---|
| | | | | | 1 |
| 66,266 | 1,135,943 | 1,320,913 | | 2,456,856 | 2 |
| 45,949 | 708,184 | 800,432 | | 1,508,616 | 3 |
| 1,009 | 14,784 | 18,178 | | 32,962 | 4 |
| 4,314 | 84,551 | 76,240 | | 160,791 | 5 |
| 3,758 | 69,810 | 66,509 | | 136,319 | 6 |
| 1,065 | 18,718 | 18,552 | | 37,270 | 7 |
| 7,944 | 121,282 | 138,382 | | 259,664 | 8 |
| 11,296 | | 972,804 | 5,222 | 978,026 | 9 |
| 38,942 | 647,854 | 772,707 | 31,272 | 1,451,833 | 10 |
| 36,686 | 562,867 | 639,293 | | 1,202,160 | 11 |
| 14,836 | | | 401,630 | 401,630 | 12 |
| | | | | | 13 |
| | | | | | 14 |
| | | | | | |
| 232,065 | 3,363,993 | 4,824,010 | 438,124 | 8,626,127 | |
| 12,112,911 | 43,978,820 | 1,815,026,920 | -1,006,681,109 | 852,324,631 | |
| **12,344,976** | **47,342,813** | **1,819,850,930** | **-1,006,242,985** | **860,950,758** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity ( i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical 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 | | | | | | |
| 2 | Nonrequirement Sales | | | | | |
| 3 | Anaheim, City of | SF | WSPP | 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 | BP Energy Company | AD | WSPP | NA | NA | NA |
| 8 | BP Energy Company | SF | WSPP | NA | NA | NA |
| 9 | Barclays Bank PLC | AD | T-12 | NA | NA | NA |
| 10 | Barclays Bank PLC | SF | T-12 | NA | NA | NA |
| 11 | Basin Electric Power Cooperative | LF | T-11 | NA | NA | NA |
| 12 | Basin Electric Power Cooperative | SF | T-11 | NA | NA | NA |
| 13 | Basin Electric Power Cooperative | SF | WSPP | NA | NA | NA |
| 14 | Bear Energy LP | SF | T-12 | NA | NA | NA |
| | | | | | | |
| | Subtotal RQ | | | 0 | 0 | 0 |
| | Subtotal non-RQ | | | 0 | 0 | 0 |
| | **Total** | | | **0** | **0** | **0** |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

| MegaWatt Hours Sold (g) | REVENUE Demand Charges ($) (h) | Energy Charges ($) (i) | Other Charges ($) (j) | Total ($) (h+i+j) (k) | Line No. |
|---|---|---|---|---|---|
| | | | | | 1 |
| | | | | | 2 |
| 300 | | 14,200 | | 14,200 | 3 |
| 313,306 | | 20,515,198 | | 20,515,198 | 4 |
| 35 | | | 2,123 | 2,123 | 5 |
| 60,895 | | 3,643,735 | | 3,643,735 | 6 |
| | | | -431 | -431 | 7 |
| 983,513 | | 61,886,095 | | 61,886,095 | 8 |
| 1,012 | | | 71,590 | 71,590 | 9 |
| 2,168,251 | | 142,441,600 | | 142,441,600 | 10 |
| 4,105 | | | 243,169 | 243,169 | 11 |
| 1,569 | | | 86,622 | 86,622 | 12 |
| 29,052 | | 1,902,018 | | 1,902,018 | 13 |
| 50,913 | | 3,773,117 | | 3,773,117 | 14 |
| | | | | | |
| 232,065 | 3,363,993 | 4,824,010 | 438,124 | 8,626,127 | |
| 12,112,911 | 43,978,820 | 1,815,026,920 | -1,006,681,109 | 852,324,631 | |
| **12,344,976** | **47,342,813** | **1,819,850,930** | **-1,006,242,985** | **860,950,758** | |

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity ( i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Benton County Public Util Dist No.1 | SF | WSPP | NA | NA | NA |
| 2 | Black Hills Power, Inc. | LF | 441 | 50 | 50 | 49 |
| 3 | Black Hills Power, Inc. | OS | WSPP | NA | NA | NA |
| 4 | Black Hills Power, Inc. | SF | WSPP | NA | NA | NA |
| 5 | Bonneville Power Administration | AD | T-13 | NA | NA | NA |
| 6 | Bonneville Power Administration | LF | 368 | NA | NA | NA |
| 7 | Bonneville Power Administration | LF | T-11 | NA | NA | NA |
| 8 | Bonneville Power Administration | LU | T-12 | NA | NA | NA |
| 9 | Bonneville Power Administration | SF | T-11 | NA | NA | NA |
| 10 | Bonneville Power Administration | SF | T-13 | NA | NA | NA |
| 11 | Bonneville Power Administration | SF | WSPP | NA | NA | NA |
| 12 | British Columbia Transmission Corp. | SF | T-13 | NA | NA | NA |
| 13 | Burbank, City of | SF | WSPP | NA | NA | NA |
| 14 | California Independent System Operator | AD | T-12 | NA | NA | NA |
| | | | | | | |
| | Subtotal RQ | | | 0 | 0 | 0 |
| | Subtotal non-RQ | | | 0 | 0 | 0 |
| | **Total** | | | **0** | **0** | **0** |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

| MegaWatt Hours Sold (g) | REVENUE Demand Charges ($) (h) | Energy Charges ($) (i) | Other Charges ($) (j) | Total ($) (h+i+j) (k) | Line No. |
|---|---|---|---|---|---|
| 4,449 | | 323,745 | | 323,745 | 1 |
| 364,969 | 6,156,421 | 5,415,098 | | 11,571,519 | 2 |
| 21,739 | | 1,349,947 | | 1,349,947 | 3 |
| 27,840 | | 1,892,358 | | 1,892,358 | 4 |
| | | | -1 | -1 | 5 |
| 2,385 | | | 137,584 | 137,584 | 6 |
| 3,031 | | | 186,196 | 186,196 | 7 |
| 40,831 | | 1,614,458 | | 1,614,458 | 8 |
| 72 | | | 2,487 | 2,487 | 9 |
| 149 | | | 5,900 | 5,900 | 10 |
| 94,062 | | 6,401,527 | | 6,401,527 | 11 |
| 37 | | | 2,430 | 2,430 | 12 |
| 51,472 | | 2,731,757 | | 2,731,757 | 13 |
| 94 | | | -308,177 | -308,177 | 14 |
| 232,065 | 3,363,993 | 4,824,010 | 438,124 | 8,626,127 | |
| 12,112,911 | 43,978,820 | 1,815,026,920 | -1,006,681,109 | 852,324,631 | |
| **12,344,976** | **47,342,813** | **1,819,850,930** | **-1,006,242,985** | **860,950,758** | |

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## SALES FOR RESALE (Account 447)

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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) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | California Independent System Operator | SF | T-12 | NA | NA | NA |
| 2 | Cargill Power Markets, LLC | AD | T-12 | NA | NA | NA |
| 3 | Cargill Power Markets, LLC | OS | T-12 | NA | NA | NA |
| 4 | Cargill Power Markets, LLC | SF | T-11 | 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 Util 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 | City of St. George | SF | WSPP | NA | NA | NA |
| 12 | Clatskanie People's Utility District | SF | WSPP | NA | NA | NA |
| 13 | Colorado River Commission of Nevada | AD | 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<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
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SALES FOR RESALE (Account 447) (Continued)

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| MegaWatt Hours Sold (g) | REVENUE Demand Charges ($) (h) | Energy Charges ($) (i) | Other Charges ($) (j) | Total ($) (h+i+j) (k) | Line No. |
|---|---|---|---|---|---|
| 246,159 | | 15,826,856 | | 15,826,856 | 1 |
| 584 | | | 97,003 | 97,003 | 2 |
| 48 | | 4,080 | | 4,080 | 3 |
| 34,258 | | | 2,071,641 | 2,071,641 | 4 |
| 12 | | | 568 | 568 | 5 |
| 928,534 | | 59,890,888 | | 59,890,888 | 6 |
| | | | 18,750 | 18,750 | 7 |
| 50 | | | 2,630 | 2,630 | 8 |
| 1,565,802 | | 106,401,687 | | 106,401,687 | 9 |
| 636 | | 29,756 | | 29,756 | 10 |
| 305 | | 30,570 | | 30,570 | 11 |
| 4,471 | | 276,998 | | 276,998 | 12 |
| 6 | | | 225 | 225 | 13 |
| 1,278 | | 97,423 | | 97,423 | 14 |
| 232,065 | 3,363,993 | 4,824,010 | 438,124 | 8,626,127 | |
| 12,112,911 | 43,978,820 | 1,815,026,920 | -1,006,681,109 | 852,324,631 | |
| **12,344,976** | **47,342,813** | **1,819,850,930** | **-1,006,242,985** | **860,950,758** | |

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) 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 | AD | T-12 | NA | NA | NA |
| 4 | Constellation Energy Commodities Group | SF | T-11 | NA | NA | NA |
| 5 | Constellation Energy Commodities Group | SF | T-11 | NA | NA | NA |
| 6 | Constellation Energy Commodities Group | SF | T-12 | NA | NA | NA |
| 7 | Credit Suisse Energy LLC | AD | T-12 | NA | NA | NA |
| 8 | Credit Suisse Energy LLC | SF | T-12 | NA | NA | NA |
| 9 | DB Energy Trading LLC | SF | T-12 | NA | NA | NA |
| 10 | Douglas County Public Util Dist No. 1 | SF | T-13 | NA | NA | NA |
| 11 | Douglas County Public Util Dist No. 1 | SF | WSPP | NA | NA | NA |
| 12 | Dynegy Power Marketing | SF | WSPP | NA | NA | NA |
| 13 | EPCOR Energy Marketing (U.S.) Inc. | SF | WSPP | NA | NA | NA |
| 14 | El Paso Electric Company | SF | WSPP | NA | NA | NA |
| | | | | | | |
| | Subtotal RQ | | | 0 | 0 | 0 |
| | Subtotal non-RQ | | | 0 | 0 | 0 |
| | **Total** | | | 0 | 0 | 0 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

SALES FOR RESALE (Account 447) (Continued)

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

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

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

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

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

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

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

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

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

| MegaWatt Hours Sold (g) | REVENUE Demand Charges ($) (h) | Energy Charges ($) (i) | Other Charges ($) (j) | Total ($) (h+i+j) (k) | Line No. |
|---|---|---|---|---|---|
| 3 | | | 175 | 175 | 1 |
| 481,860 | | 33,106,821 | | 33,106,821 | 2 |
| 1,063 | | | 82,023 | 82,023 | 3 |
| 21,425 | | | 1,317,926 | 1,317,926 | 4 |
| 247 | | | 14,833 | 14,833 | 5 |
| 1,320,102 | | 88,827,748 | | 88,827,748 | 6 |
| 204 | | | 14,013 | 14,013 | 7 |
| 666,147 | | 50,682,876 | | 50,682,876 | 8 |
| 344,696 | | 22,255,189 | | 22,255,189 | 9 |
| 1 | | | 90 | 90 | 10 |
| 360 | | 29,840 | | 29,840 | 11 |
| 75 | | 3,517 | | 3,517 | 12 |
| 5,800 | | 487,240 | | 487,240 | 13 |
| 38,833 | | 2,618,607 | | 2,618,607 | 14 |
| | | | | | |
| 232,065 | 3,363,993 | 4,824,010 | 438,124 | 8,626,127 | |
| 12,112,911 | 43,978,820 | 1,815,026,920 | -1,006,681,109 | 852,324,631 | |
| **12,344,976** | **47,342,813** | **1,819,850,930** | **-1,006,242,985** | **860,950,758** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity ( i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

| Line No. | Name of Company or Public Authority (Footnote Affiliations)<br>(a) | Statistical Classification<br>(b) | FERC Rate Schedule or Tariff Number<br>(c) | Average Monthly Billing Demand (MW)<br>(d) | Actual Demand (MW) | |
|---|---|---|---|---|---|---|
| | | | | | Average Monthly NCP Demand<br>(e) | Average Monthly CP Demand<br>(f) |
| 1 | Eugene Water & Electric Board | SF | T-11 | NA | NA | NA |
| 2 | Eugene Water & Electric Board | SF | WSPP | NA | NA | NA |
| 3 | FPL Energy Power Marketing, Inc. | SF | WSPP | NA | NA | NA |
| 4 | Fortis Energy Marketing & Trading GP | AD | WSPP | NA | NA | NA |
| 5 | Fortis Energy Marketing & Trading GP | SF | WSPP | NA | NA | NA |
| 6 | Franklin County Public Util Dist No. 1 | SF | WSPP | NA | NA | NA |
| 7 | Gila River Power, L.P. | SF | WSPP | NA | NA | NA |
| 8 | Glendale, City of | SF | WSPP | NA | NA | NA |
| 9 | Grant County Public Utility Dist No. 1 | SF | WSPP | NA | NA | NA |
| 10 | Grays Harbor Public Utility District | SF | WSPP | NA | NA | NA |
| 11 | Highland Energy LLC | SF | T-11 | NA | NA | NA |
| 12 | Highland Energy LLC | SF | WSPP | NA | NA | NA |
| 13 | Hurricane, City of | LF | T-12 | NA | NA | NA |
| 14 | Iberdrola Renewables, Inc. | AD | T-11 | NA | NA | NA |
| | | | | | | |
| | Subtotal RQ | | | 0 | 0 | 0 |
| | Subtotal non-RQ | | | 0 | 0 | 0 |
| | **Total** | | | 0 | 0 | 0 |

SALES FOR RESALE (Account 447) (Continued)

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

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

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

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

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

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

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

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

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

| MegaWatt Hours Sold (g) | REVENUE Demand Charges ($) (h) | Energy Charges ($) (i) | Other Charges ($) (j) | Total ($) (h+i+j) (k) | Line No. |
|---|---|---|---|---|---|
| 409 | | | 31,860 | 31,860 | 1 |
| 21,813 | | 1,362,957 | | 1,362,957 | 2 |
| 45,205 | | 3,648,785 | | 3,648,785 | 3 |
| 82 | | | 4,305 | 4,305 | 4 |
| 298,477 | | 20,978,272 | | 20,978,272 | 5 |
| 1,770 | | 125,940 | | 125,940 | 6 |
| 71,397 | | 3,939,812 | | 3,939,812 | 7 |
| 53 | | 3,074 | | 3,074 | 8 |
| 10,720 | | 603,075 | | 603,075 | 9 |
| 2,582 | | 186,668 | | 186,668 | 10 |
| 4 | | | 197 | 197 | 11 |
| 33,116 | | 2,044,194 | | 2,044,194 | 12 |
| 153 | | 11,475 | | 11,475 | 13 |
| -9 | | | -459 | -459 | 14 |
| | | | | | |
| 232,065 | 3,363,993 | 4,824,010 | 438,124 | 8,626,127 | |
| 12,112,911 | 43,978,820 | 1,815,026,920 | -1,006,681,109 | 852,324,631 | |
| **12,344,976** | **47,342,813** | **1,819,850,930** | **-1,006,242,985** | **860,950,758** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original (2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity ( i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
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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) | 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 | Iberdrola Renewables, Inc. | LF | T-11 | NA | NA | NA |
| 2 | Iberdrola Renewables, Inc. | SF | T-11 | NA | NA | NA |
| 3 | Iberdrola Renewables, Inc. | SF | T-12 | NA | NA | NA |
| 4 | Idaho Power Company | IF | T-11 | NA | NA | NA |
| 5 | Idaho Power Company | SF | T-11 | NA | NA | NA |
| 6 | Idaho Power Company | SF | T-11 | NA | NA | NA |
| 7 | Idaho Power Company | SF | T-13 | NA | NA | NA |
| 8 | Idaho Power Company | SF | WSPP | NA | NA | NA |
| 9 | Integrys Energy Services, Inc. | SF | T-11 | NA | NA | NA |
| 10 | Integrys Energy Services, Inc. | SF | WSPP | NA | NA | NA |
| 11 | J. Aron & Company | SF | T-12 | NA | NA | NA |
| 12 | J.P. Morgan Ventures Energy Corporation | SF | T-12 | NA | NA | NA |
| 13 | Lehman Brothers Commodity Services, Inc | SF | T-12 | NA | NA | NA |
| 14 | Los Angeles Dept. of Water & Power | LU | 301 | NA | NA | NA |
| | | | | | | |
| | Subtotal RQ | | | 0 | 0 | 0 |
| | Subtotal non-RQ | | | 0 | 0 | 0 |
| | **Total** | | | **0** | **0** | **0** |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

SALES FOR RESALE (Account 447) (Continued)

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

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

| MegaWatt Hours Sold (g) | REVENUE Demand Charges ($) (h) | Energy Charges ($) (i) | Other Charges ($) (j) | Total ($) (h+i+j) (k) | Line No. |
|---|---|---|---|---|---|
| 61 | | | 3,969 | 3,969 | 1 |
| 17,272 | | | 1,014,454 | 1,014,454 | 2 |
| 393,688 | | 24,470,668 | | 24,470,668 | 3 |
| 2,029 | | | 106,248 | 106,248 | 4 |
| 6,286 | | | 442,628 | 442,628 | 5 |
| 9 | | | 420 | 420 | 6 |
| 304 | | | 13,501 | 13,501 | 7 |
| 143,332 | | 8,466,149 | | 8,466,149 | 8 |
| 481 | | | 19,471 | 19,471 | 9 |
| 20,159 | | 1,301,489 | | 1,301,489 | 10 |
| 444,556 | | 31,958,680 | | 31,958,680 | 11 |
| 128,732 | | 9,168,330 | | 9,168,330 | 12 |
| 96,835 | | 6,549,555 | | 6,549,555 | 13 |
| 582,894 | | 25,898,987 | | 25,898,987 | 14 |
| 232,065 | 3,363,993 | 4,824,010 | 438,124 | 8,626,127 | |
| 12,112,911 | 43,978,820 | 1,815,026,920 | -1,006,681,109 | 852,324,631 | |
| **12,344,976** | **47,342,813** | **1,819,850,930** | **-1,006,242,985** | **860,950,758** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
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## SALES FOR RESALE (Account 447)

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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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| 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 | WSPP | NA | NA | NA |
| 2 | Louis Dreyfus Energy Services L.P. | SF | WSPP | NA | NA | NA |
| 3 | Macquarie Cook Power Inc. | SF | WSPP | NA | NA | NA |
| 4 | Merrill Lynch Commodities, Inc. | SF | WSPP | NA | NA | NA |
| 5 | Metropolitan Water District | SF | WSPP | NA | NA | NA |
| 6 | Modesto Irrigation District | SF | WSPP | NA | NA | NA |
| 7 | Morgan Stanley Capital Group, Inc. | AD | T-12 | NA | NA | NA |
| 8 | Morgan Stanley Capital Group, Inc. | SF | T-11 | NA | NA | NA |
| 9 | Morgan Stanley Capital Group, Inc. | SF | T-12 | NA | NA | NA |
| 10 | Municipal Energy Agency of Nebraska | SF | T-11 | NA | NA | NA |
| 11 | Municipal Energy Agency of Nebraska | SF | WSPP | NA | NA | NA |
| 12 | Nevada Power Company | SF | T-11 | NA | NA | NA |
| 13 | Nevada Power Company | SF | WSPP | NA | NA | NA |
| 14 | NorthWestern Energy | SF | T-13 | NA | NA | NA |
| | Subtotal RQ | | | 0 | 0 | 0 |
| | Subtotal non-RQ | | | 0 | 0 | 0 |
| | **Total** | | | **0** | **0** | **0** |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

SALES FOR RESALE (Account 447) (Continued)

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

| MegaWatt Hours Sold (g) | REVENUE: Demand Charges ($) (h) | Energy Charges ($) (i) | Other Charges ($) (j) | Total ($) (h+i+j) (k) | Line No. |
|---|---|---|---|---|---|
| 176,620 | | 9,280,674 | | 9,280,674 | 1 |
| 1,078 | | 74,606 | | 74,606 | 2 |
| 1,200 | | 71,600 | | 71,600 | 3 |
| 44,525 | | 3,078,410 | | 3,078,410 | 4 |
| 2,997 | | 122,888 | | 122,888 | 5 |
| 45,820 | | 3,067,591 | | 3,067,591 | 6 |
| 1,386 | | | 62,349 | 62,349 | 7 |
| 9,607 | | | 641,927 | 641,927 | 8 |
| 4,713,228 | | 303,595,575 | 28,800 | 303,624,375 | 9 |
| 14 | | | 536 | 536 | 10 |
| 6,754 | | 533,969 | | 533,969 | 11 |
| 160 | | | 7,089 | 7,089 | 12 |
| 160 | | 12,150 | | 12,150 | 13 |
| 377 | | | 24,421 | 24,421 | 14 |
| 232,065 | 3,363,993 | 4,824,010 | 438,124 | 8,626,127 | |
| 12,112,911 | 43,978,820 | 1,815,026,920 | -1,006,681,109 | 852,324,631 | |
| **12,344,976** | **47,342,813** | **1,819,850,930** | **-1,006,242,985** | **860,950,758** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity ( i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classifi-cation (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | NorthWestern Energy | SF | WSPP | NA | NA | NA |
| 2 | Northern California Power Agency | SF | WSPP | NA | NA | NA |
| 3 | Northpoint Energy Solutions Inc. | SF | WSPP | NA | NA | NA |
| 4 | Occidental Power Services, Inc. | SF | WSPP | NA | NA | NA |
| 5 | PPL EnergyPlus, LLC | SF | WSPP | NA | NA | NA |
| 6 | PPL Montana, LLC | SF | T-11 | NA | NA | NA |
| 7 | Pacific Gas & Electric Company | SF | WSPP | NA | NA | NA |
| 8 | Pacific NW Generating Cooperative | SF | WSPP | NA | NA | NA |
| 9 | Pacific Summit Energy LLC | SF | T-12 | NA | NA | NA |
| 10 | Pasadena, City of | SF | WSPP | NA | NA | NA |
| 11 | Portland General Electric Co. | SF | T-11 | NA | NA | NA |
| 12 | Portland General Electric Co. | SF | T-12 | NA | NA | NA |
| 13 | Portland General Electric Co. | SF | T-13 | NA | NA | NA |
| 14 | Powerex | AD | WSPP | NA | NA | NA |
| | | | | | | |
| | Subtotal RQ | | | 0 | 0 | 0 |
| | Subtotal non-RQ | | | 0 | 0 | 0 |
| | **Total** | | | **0** | **0** | **0** |

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

| MegaWatt Hours Sold (g) | REVENUE Demand Charges ($) (h) | Energy Charges ($) (i) | Other Charges ($) (j) | Total ($) (h+i+j) (k) | Line No. |
|---|---|---|---|---|---|
| 4,787 | | 296,988 | | 296,988 | 1 |
| 7,440 | | 587,824 | | 587,824 | 2 |
| 8,905 | | 640,674 | | 640,674 | 3 |
| 4,025 | | 275,445 | | 275,445 | 4 |
| 43,390 | | 2,311,628 | | 2,311,628 | 5 |
| 822 | | | 50,904 | 50,904 | 6 |
| 144,811 | | 11,766,890 | | 11,766,890 | 7 |
| 17,675 | | 1,257,625 | | 1,257,625 | 8 |
| 61,764 | | 3,352,229 | | 3,352,229 | 9 |
| 480 | | 23,680 | | 23,680 | 10 |
| 74 | | | 4,183 | 4,183 | 11 |
| 386,735 | | 23,910,040 | | 23,910,040 | 12 |
| 332 | | | 21,116 | 21,116 | 13 |
| 310 | | | 19,910 | 19,910 | 14 |
| 232,065 | 3,363,993 | 4,824,010 | 438,124 | 8,626,127 | |
| 12,112,911 | 43,978,820 | 1,815,026,920 | -1,006,681,109 | 852,324,631 | |
| **12,344,976** | **47,342,813** | **1,819,850,930** | **-1,006,242,985** | **860,950,758** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity ( i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

| Line No. | Name of Company or Public Authority (Footnote Affiliations)<br>(a) | Statistical Classification<br>(b) | FERC Rate Schedule or Tariff Number<br>(c) | Average Monthly Billing Demand (MW)<br>(d) | Actual Demand (MW) Average Monthly NCP Demand<br>(e) | Actual Demand (MW) Average Monthly CP Demand<br>(f) |
|---|---|---|---|---|---|---|
| 1 | Powerex | IF | T-11 | NA | NA | NA |
| 2 | Powerex | SF | T-11 | NA | NA | NA |
| 3 | Powerex | SF | WSPP | NA | NA | NA |
| 4 | Public Service Company of Colorado | AD | 320 | NA | NA | NA |
| 5 | Public Service Company of Colorado | AD | WSPP | NA | NA | NA |
| 6 | Public Service Company of Colorado | LF | 320 | 141 | 145 | 134 |
| 7 | Public Service Company of Colorado | OS | WSPP | NA | NA | NA |
| 8 | Public Service Company of Colorado | SF | T-11 | NA | NA | NA |
| 9 | Public Service Company of Colorado | SF | WSPP | NA | NA | NA |
| 10 | Public Service Company of New Mexico | SF | WSPP | NA | NA | NA |
| 11 | Puget Sound Energy | SF | T-13 | NA | NA | NA |
| 12 | Puget Sound Energy | SF | WSPP | NA | NA | NA |
| 13 | Rainbow Energy Marketing | SF | T-11 | NA | NA | NA |
| 14 | Rainbow Energy Marketing | SF | WSPP | NA | NA | NA |
| | Subtotal RQ | | | 0 | 0 | 0 |
| | Subtotal non-RQ | | | 0 | 0 | 0 |
| | **Total** | | | **0** | **0** | **0** |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

| MegaWatt Hours Sold (g) | REVENUE Demand Charges ($) (h) | Energy Charges ($) (i) | Other Charges ($) (j) | Total ($) (h+i+j) (k) | Line No. |
|---|---|---|---|---|---|
| 14,858 | | | 881,878 | 881,878 | 1 |
| 32,575 | | | 2,057,754 | 2,057,754 | 2 |
| 1,120,902 | | 61,237,043 | | 61,237,043 | 3 |
| 32 | | | -316,997 | -316,997 | 4 |
| 127 | | | 7,202 | 7,202 | 5 |
| 932,165 | 18,679,680 | 43,289,975 | | 61,969,655 | 6 |
| 940 | | 25,800 | | 25,800 | 7 |
| 494 | | | 26,722 | 26,722 | 8 |
| 106,188 | | 6,771,774 | | 6,771,774 | 9 |
| 129,727 | | 8,041,429 | | 8,041,429 | 10 |
| 211 | | | 14,144 | 14,144 | 11 |
| 290,738 | | 16,831,943 | | 16,831,943 | 12 |
| 6,165 | | | 364,435 | 364,435 | 13 |
| 73,132 | | 4,884,326 | | 4,884,326 | 14 |
| 232,065 | 3,363,993 | 4,824,010 | 438,124 | 8,626,127 | |
| 12,112,911 | 43,978,820 | 1,815,026,920 | -1,006,681,109 | 852,324,631 | |
| **12,344,976** | **47,342,813** | **1,819,850,930** | **-1,006,242,985** | **860,950,758** | |

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## SALES FOR RESALE (Account 447)

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2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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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) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Redding, City of | SF | WSPP | NA | NA | NA |
| 2 | SUEZ Energy Marketing NA, Inc. | SF | WSPP | NA | NA | NA |
| 3 | Sacramento Municipal Utility District | AD | 250 | NA | NA | NA |
| 4 | Sacramento Municipal Utility District | LF | 250 | NA | NA | NA |
| 5 | Sacramento Municipal Utility District | SF | WSPP | NA | NA | NA |
| 6 | Salt River Project | IF | WSPP | NA | NA | NA |
| 7 | Salt River Project | OS | WSPP | NA | NA | NA |
| 8 | Salt River Project | SF | WSPP | NA | NA | NA |
| 9 | San Diego Gas & Electric | SF | WSPP | NA | NA | NA |
| 10 | Santa Clara, City of | SF | WSPP | NA | NA | NA |
| 11 | Seattle City Light | SF | T-13 | NA | NA | NA |
| 12 | Seattle City Light | SF | WSPP | NA | NA | NA |
| 13 | Sempra Energy Solutions | SF | WSPP | NA | NA | NA |
| 14 | Sempra Energy Trading LLC | AD | T-12 | NA | NA | NA |
| | | | | | | |
| | Subtotal RQ | | | 0 | 0 | 0 |
| | Subtotal non-RQ | | | 0 | 0 | 0 |
| | **Total** | | | **0** | **0** | **0** |

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
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5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
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7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
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10. Footnote entries as required and provide explanations following all required data.

| MegaWatt Hours Sold (g) | REVENUE Demand Charges ($) (h) | Energy Charges ($) (i) | Other Charges ($) (j) | Total ($) (h+i+j) (k) | Line No. |
|---|---|---|---|---|---|
| 21,530 | | 1,182,137 | | 1,182,137 | 1 |
| 12,756 | | 969,632 | | 969,632 | 2 |
| | | | 461,219 | 461,219 | 3 |
| 570,608 | | 12,245,248 | | 12,245,248 | 4 |
| 111,835 | | 7,204,413 | | 7,204,413 | 5 |
| 219,596 | | 14,014,987 | | 14,014,987 | 6 |
| 6,892 | | 575,652 | | 575,652 | 7 |
| 83,737 | | 5,021,962 | | 5,021,962 | 8 |
| 35,417 | | 2,487,761 | | 2,487,761 | 9 |
| 8,827 | | 573,554 | | 573,554 | 10 |
| 3 | | | 191 | 191 | 11 |
| 54,753 | | 3,329,190 | | 3,329,190 | 12 |
| 600 | | 32,108 | | 32,108 | 13 |
| 148 | | | 15,620 | 15,620 | 14 |
| 232,065 | 3,363,993 | 4,824,010 | 438,124 | 8,626,127 | |
| 12,112,911 | 43,978,820 | 1,815,026,920 | -1,006,681,109 | 852,324,631 | |
| **12,344,976** | **47,342,813** | **1,819,850,930** | **-1,006,242,985** | **860,950,758** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## SALES FOR RESALE (Account 447)

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classifi-cation (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Sempra Energy Trading LLC | SF | T-11 | NA | NA | NA |
| 2 | Sempra Energy Trading LLC | SF | T-12 | NA | NA | NA |
| 3 | Sempra Generation | SF | T-12 | NA | NA | NA |
| 4 | Shell Energy North America (US), L.P. | AD | WSPP | NA | NA | NA |
| 5 | Shell Energy North America (US), L.P. | SF | T-11 | NA | NA | NA |
| 6 | Shell Energy North America (US), L.P. | SF | WSPP | NA | NA | NA |
| 7 | Sierra Pacific Power Company | AD | 258 | NA | NA | NA |
| 8 | Sierra Pacific Power Company | LF | 258 | 75 | 75 | 72 |
| 9 | Sierra Pacific Power Company | LF | T-11 | NA | NA | NA |
| 10 | Sierra Pacific Power Company | SF | T-11 | NA | NA | NA |
| 11 | Sierra Pacific Power Company | SF | T-13 | NA | NA | NA |
| 12 | Sierra Pacific Power Company | SF | WSPP | NA | NA | NA |
| 13 | Snohomish Public Utility District No. 1 | SF | WSPP | NA | NA | NA |
| 14 | Southern California Edison Company | SF | T-12 | NA | NA | NA |
| | | | | | | |
| | Subtotal RQ | | | 0 | 0 | 0 |
| | Subtotal non-RQ | | | 0 | 0 | 0 |
| | **Total** | | | **0** | **0** | **0** |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

SALES FOR RESALE (Account 447) (Continued)

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

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

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

| MegaWatt Hours Sold (g) | REVENUE: Demand Charges ($) (h) | Energy Charges ($) (i) | Other Charges ($) (j) | Total ($) (h+i+j) (k) | Line No. |
|---|---|---|---|---|---|
| 90 | | | 4,953 | 4,953 | 1 |
| 3,542,856 | | 225,132,372 | | 225,132,372 | 2 |
| 3,800 | | 282,720 | | 282,720 | 3 |
| 7 | | | 525 | 525 | 4 |
| 213 | | | 12,793 | 12,793 | 5 |
| 1,187,655 | | 77,325,859 | 2,000 | 77,327,859 | 6 |
| | | | 157,386 | 157,386 | 7 |
| 461,337 | 14,715,000 | 19,634,503 | | 34,349,503 | 8 |
| 1,043 | | | 61,597 | 61,597 | 9 |
| 14,936 | | | 966,315 | 966,315 | 10 |
| 824 | | | 45,771 | 45,771 | 11 |
| 3 | | 142 | | 142 | 12 |
| 42,665 | | 2,638,856 | | 2,638,856 | 13 |
| 81,730 | | 6,704,415 | | 6,704,415 | 14 |
| | | | | | |
| 232,065 | 3,363,993 | 4,824,010 | 438,124 | 8,626,127 | |
| 12,112,911 | 43,978,820 | 1,815,026,920 | -1,006,681,109 | 852,324,631 | |
| **12,344,976** | **47,342,813** | **1,819,850,930** | **-1,006,242,985** | **860,950,758** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity ( i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Southwestern Public Service Company | SF | WSPP | NA | NA | NA |
| 2 | State of CA Dept of Water Resources | SF | WSPP | NA | NA | NA |
| 3 | Tacoma, City of | SF | WSPP | NA | NA | NA |
| 4 | The Energy Authority | SF | WSPP | NA | NA | NA |
| 5 | TransAlta Energy Marketing Inc. | IF | T-12 | NA | NA | NA |
| 6 | TransAlta Energy Marketing Inc. | SF | T-11 | NA | NA | NA |
| 7 | TransAlta Energy Marketing Inc. | SF | T-12 | NA | NA | NA |
| 8 | Tri-State Generation & Transmission | SF | T-11 | NA | NA | NA |
| 9 | Tri-State Generation & Transmission | SF | WSPP | 0.7 | 0.7 | 0.1 |
| 10 | Tucson Electric Power | AD | WSPP | NA | NA | NA |
| 11 | Tucson Electric Power | SF | WSPP | NA | NA | NA |
| 12 | Turlock Irrigation District | SF | WSPP | NA | NA | NA |
| 13 | UBS Warburg Energy LLC | SF | T-12 | NA | NA | NA |
| 14 | UNS Electric, Inc. | SF | WSPP | NA | NA | NA |
| | Subtotal RQ | | | 0 | 0 | 0 |
| | Subtotal non-RQ | | | 0 | 0 | 0 |
| | **Total** | | | **0** | **0** | **0** |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

SALES FOR RESALE (Account 447) (Continued)

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

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

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

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

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

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

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

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

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

| MegaWatt Hours Sold (g) | REVENUE Demand Charges ($) (h) | Energy Charges ($) (i) | Other Charges ($) (j) | Total ($) (h+i+j) (k) | Line No. |
|---|---|---|---|---|---|
| 14,599 | | 1,025,417 | | 1,025,417 | 1 |
| 13,125 | | 784,346 | | 784,346 | 2 |
| 5,030 | | 323,515 | | 323,515 | 3 |
| 21,905 | | 1,406,605 | | 1,406,605 | 4 |
| 826,275 | | 48,566,924 | | 48,566,924 | 5 |
| 2,589 | | | 198,944 | 198,944 | 6 |
| 130,446 | | 7,827,728 | | 7,827,728 | 7 |
| 684 | | | 55,086 | 55,086 | 8 |
| 126,806 | 31,519 | 9,138,722 | | 9,170,241 | 9 |
| 180 | | | 11,825 | 11,825 | 10 |
| 189,666 | | 12,725,255 | | 12,725,255 | 11 |
| 25,490 | | 1,362,832 | | 1,362,832 | 12 |
| 605,114 | | 40,209,842 | | 40,209,842 | 13 |
| 22,075 | | 845,575 | | 845,575 | 14 |
| 232,065 | 3,363,993 | 4,824,010 | 438,124 | 8,626,127 | |
| 12,112,911 | 43,978,820 | 1,815,026,920 | -1,006,681,109 | 852,324,631 | |
| **12,344,976** | **47,342,813** | **1,819,850,930** | **-1,006,242,985** | **860,950,758** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity ( i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

| Line No. | Name of Company or Public Authority (Footnote Affiliations) | 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 | Utah Associated Municipal Power Systems | OS | WSPP | NA | NA | NA |
| 2 | Utah Associated Municipal Power Systems | SF | WSPP | NA | NA | NA |
| 3 | Utah Municipal Power Agency | LF | 433 | 34 | 34 | 34 |
| 4 | Utah Municipal Power Agency | SF | T-3 | NA | NA | NA |
| 5 | Western Area Power Administration | OS | WSPP | NA | NA | NA |
| 6 | Western Area Power Administration | SF | T-11 | NA | NA | NA |
| 7 | Western Area Power Administration | SF | T-13 | NA | NA | NA |
| 8 | Western Area Power Administration | SF | WSPP | NA | NA | NA |
| 9 | Bookout Sales | AD | NA | NA | NA | NA |
| 10 | Test Generation | AD | NA | NA | NA | NA |
| 11 | Test Generation | AD | NA | NA | NA | NA |
| 12 | Trade Sales | AD | NA | NA | NA | NA |
| 13 | Accrual True-up | NA | NA | NA | NA | NA |
| 14 | | | | | | |
| | Subtotal RQ | | | 0 | 0 | 0 |
| | Subtotal non-RQ | | | 0 | 0 | 0 |
| | **Total** | | | **0** | **0** | **0** |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

SALES FOR RESALE (Account 447) (Continued)

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

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

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

| MegaWatt Hours Sold (g) | REVENUE: Demand Charges ($) (h) | Energy Charges ($) (i) | Other Charges ($) (j) | Total ($) (h+i+j) (k) | Line No. |
|---|---|---|---|---|---|
| 17,565 | | 702,600 | | 702,600 | 1 |
| 4,970 | | 406,900 | | 406,900 | 2 |
| 223,859 | 4,396,200 | 5,202,483 | | 9,598,683 | 3 |
| 776 | | 38,253 | | 38,253 | 4 |
| 338 | | 28,980 | | 28,980 | 5 |
| 45 | | | 2,342 | 2,342 | 6 |
| 2 | | | 157 | 157 | 7 |
| 329,292 | | 24,539,597 | | 24,539,597 | 8 |
| -17,456,425 | | | -886,623,896 | -886,623,896 | 9 |
| -60 | | | 32,083 | 32,083 | 10 |
| -55,899 | | | -3,072,975 | -3,072,975 | 11 |
| | | | -127,855,541 | -127,855,541 | 12 |
| -2,577 | | | -739,840 | -739,840 | 13 |
| | | | | | 14 |
| 232,065 | 3,363,993 | 4,824,010 | 438,124 | 8,626,127 | |
| 12,112,911 | 43,978,820 | 1,815,026,920 | -1,006,681,109 | 852,324,631 | |
| **12,344,976** | **47,342,813** | **1,819,850,930** | **-1,006,242,985** | **860,950,758** | |

***Schedule Page: 310 Line No.: 9 Column: j***
Settlement Adjustment

***Schedule Page: 310 Line No.: 10 Column: j***
Fixed charge for the first six months of the contract to recover cost.

***Schedule Page: 310 Line No.: 12 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: 310.1 Line No.: 5 Column: j***
Reserve Share

***Schedule Page: 310.1 Line No.: 7 Column: b***
Settlement Adjustment

***Schedule Page: 310.1 Line No.: 7 Column: j***
Settlement Adjustment

***Schedule Page: 310.1 Line No.: 9 Column: b***
Settlement Adjustment

***Schedule Page: 310.1 Line No.: 9 Column: j***
Settlement Adjustment

***Schedule Page: 310.1 Line No.: 11 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.: 11 Column: j***
Transmission Losses

***Schedule Page: 310.1 Line No.: 12 Column: j***
Transmission Losses

***Schedule Page: 310.2 Line No.: 2 Column: b***
Black Hills Power & Light Company - FERC 441 - Contract termination date: December 31, 2023.

***Schedule Page: 310.2 Line No.: 3 Column: b***
Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

***Schedule Page: 310.2 Line No.: 5 Column: b***
Settlement Adjustment

***Schedule Page: 310.2 Line No.: 5 Column: j***
Settlement Adjustment

***Schedule Page: 310.2 Line No.: 6 Column: b***
Bonneville Power Administration - FERC 368 [Use of Facilities Agreement for the Malin Transformer under the AC Intertie Agreement wtih BPA] - Contract termination date: Upon mutual agreement.

***Schedule Page: 310.2 Line No.: 6 Column: j***
Transmission Losses

***Schedule Page: 310.2 Line No.: 7 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.: 7 Column: j***
Transmission Losses

***Schedule Page: 310.2 Line No.: 8 Column: b***
Bonneville Power Administration - FERC T-12 - Contract termination date: April 22, 2024.

***Schedule Page: 310.2 Line No.: 9 Column: j***
Transmission Losses

***Schedule Page: 310.2 Line No.: 10 Column: j***
Reserve Share

***Schedule Page: 310.2 Line No.: 12 Column: j***
Reserve Share

***Schedule Page: 310.2 Line No.: 14 Column: b***

Settlement Adjustment

***Schedule Page: 310.2 Line No.: 14 Column: j***

Settlement Adjustment

***Schedule Page: 310.3 Line No.: 2 Column: b***

Settlement Adjustment

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

Settlement Adjustment

***Schedule Page: 310.3 Line No.: 3 Column: b***

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

***Schedule Page: 310.3 Line No.: 4 Column: j***

Transmission Losses

***Schedule Page: 310.3 Line No.: 5 Column: j***

Unauthorized use charges

***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.: 13 Column: b***

Settlement Adjustment

***Schedule Page: 310.3 Line No.: 13 Column: j***

Settlement Adjustment

***Schedule Page: 310.4 Line No.: 1 Column: j***

Transmission Losses

***Schedule Page: 310.4 Line No.: 3 Column: b***

Settlement Adjustment

***Schedule Page: 310.4 Line No.: 3 Column: j***

Settlement Adjustment

***Schedule Page: 310.4 Line No.: 4 Column: j***

Transmission Losses

***Schedule Page: 310.4 Line No.: 5 Column: j***

Unauthorized use charges

***Schedule Page: 310.4 Line No.: 7 Column: b***

Settlement Adjustment

***Schedule Page: 310.4 Line No.: 7 Column: j***

Settlement Adjustment

***Schedule Page: 310.4 Line No.: 10 Column: j***

Reserve Share

***Schedule Page: 310.5 Line No.: 1 Column: j***

Transmission Losses

***Schedule Page: 310.5 Line No.: 4 Column: b***

Settlement Adjustment

***Schedule Page: 310.5 Line No.: 4 Column: j***

Settlement Adjustment

***Schedule Page: 310.5 Line No.: 11 Column: j***

Transmission Losses

***Schedule Page: 310.5 Line No.: 13 Column: b***

Hurricane, City of - FERC T-12 - Contract termination date: August 31, 2007.

***Schedule Page: 310.5 Line No.: 14 Column: b***

Settlement Adjustment

***Schedule Page: 310.5 Line No.: 14 Column: j***

Settlement Adjustment

***Schedule Page: 310.6 Line No.: 1 Column: b***

Iberdola Renewables, Inc. - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 279)] - Contract termination date: April 30, 2009.

***Schedule Page: 310.6 Line No.: 1 Column: j***

Transmission Losses

***Schedule Page: 310.6 Line No.: 2 Column: j***

Transmission Losses

***Schedule Page: 310.6 Line No.: 4 Column: b***

Idaho Power Company - T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 212)] - Contract termination date: May 31, 2009.

***Schedule Page: 310.6 Line No.: 4 Column: j***

Transmission Losses

***Schedule Page: 310.6 Line No.: 5 Column: j***

Transmission Losses

***Schedule Page: 310.6 Line No.: 6 Column: j***

Unauthorized use charges

***Schedule Page: 310.6 Line No.: 7 Column: j***

Reserve Share

***Schedule Page: 310.6 Line No.: 9 Column: j***

Transmission Losses

***Schedule Page: 310.6 Line No.: 14 Column: b***

Los Angeles Department of Water and Power - FERC 301 - Contract termination date: June 15, 2027.

***Schedule Page: 310.7 Line No.: 7 Column: b***

Settlement Adjustment

***Schedule Page: 310.7 Line No.: 7 Column: j***

Settlement Adjustment

***Schedule Page: 310.7 Line No.: 8 Column: j***

Transmission Losses

***Schedule Page: 310.7 Line No.: 9 Column: j***

Liquidated Damages

***Schedule Page: 310.7 Line No.: 10 Column: j***

Transmission Losses

***Schedule Page: 310.7 Line No.: 12 Column: j***

Transmission Losses

***Schedule Page: 310.7 Line No.: 14 Column: j***

Reserve Share

***Schedule Page: 310.8 Line No.: 6 Column: j***

Transmission Losses

***Schedule Page: 310.8 Line No.: 11 Column: j***

Transmission Losses

***Schedule Page: 310.8 Line No.: 13 Column: j***

Reserve Share

***Schedule Page: 310.8 Line No.: 14 Column: b***

Settlement Adjustment

***Schedule Page: 310.8 Line No.: 14 Column: j***

Settlement Adjustment

***Schedule Page: 310.9 Line No.: 1 Column: b***

Powerex - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 363)] - Contract termination date: September 30, 2012.

***Schedule Page: 310.9 Line No.: 1 Column: j***

Transmission Losses

| Name of Respondent<br>PacifiCorp | This Report is:<br>(1) X An Original<br>(2) _ A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>2008/Q4 |
|---|---|---|---|

FOOTNOTE DATA

**Schedule Page: 310.9 Line No.: 2 Column: j**

Transmission Losses

**Schedule Page: 310.9 Line No.: 4 Column: b**

Settlement Adjustment

**Schedule Page: 310.9 Line No.: 4 Column: j**

Settlement Adjustment

**Schedule Page: 310.9 Line No.: 5 Column: b**

Settlement Adjustment

**Schedule Page: 310.9 Line No.: 5 Column: j**

Settlement Adjustment

**Schedule Page: 310.9 Line No.: 6 Column: b**

Imbalance energy.

**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.: 8 Column: j**

Transmission Losses

**Schedule Page: 310.9 Line No.: 11 Column: j**

Reserve Share

**Schedule Page: 310.9 Line No.: 13 Column: j**

Transmission Losses

**Schedule Page: 310.10 Line No.: 3 Column: b**

Settlement Adjustment

**Schedule Page: 310.10 Line No.: 3 Column: j**

Settlement Adjustment

**Schedule Page: 310.10 Line No.: 4 Column: b**

Sacramento Municipal Utility District - FERC 250 - Contract termination date: December 31, 2014.

**Schedule Page: 310.10 Line No.: 6 Column: b**

Salt River Project - WSPP - Contract termination date: December 31, 2009.

**Schedule Page: 310.10 Line No.: 7 Column: b**

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

**Schedule Page: 310.10 Line No.: 11 Column: j**

Reserve Share

**Schedule Page: 310.10 Line No.: 14 Column: b**

Settlement Adjustment

**Schedule Page: 310.10 Line No.: 14 Column: j**

Settlement Adjustment

**Schedule Page: 310.11 Line No.: 1 Column: j**

Transmission Losses

**Schedule Page: 310.11 Line No.: 4 Column: b**

Settlement Adjustment

**Schedule Page: 310.11 Line No.: 4 Column: j**

Settlement Adjustment

**Schedule Page: 310.11 Line No.: 5 Column: j**

Transmission Losses

**Schedule Page: 310.11 Line No.: 6 Column: j**

Pond Sale

**Schedule Page: 310.11 Line No.: 7 Column: b**

Settlement Adjustment

**Schedule Page: 310.11 Line No.: 7 Column: j**

Settlement Adjustment

**Schedule Page: 310.11 Line No.: 8 Column: b**

Sierra Pacific Power Company - FERC 258 - Contract termination date: February 28, 2009.

***Schedule Page: 310.11 Line No.: 9 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.: 9 Column: j***

Transmission Losses

***Schedule Page: 310.11 Line No.: 10 Column: j***

Transmission Losses

***Schedule Page: 310.11 Line No.: 11 Column: j***

Reserve Share

***Schedule Page: 310.12 Line No.: 5 Column: b***

TransAlta Energy Marketing Inc. - FERC T-12 - Contract termination date: December 31, 2010.

***Schedule Page: 310.12 Line No.: 6 Column: j***

Transmission Losses

***Schedule Page: 310.12 Line No.: 8 Column: j***

Transmission Losses

***Schedule Page: 310.12 Line No.: 10 Column: b***

Settlement Adjustment

***Schedule Page: 310.12 Line No.: 10 Column: j***

Settlement Adjustment

***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.: 3 Column: b***

Utah Municipal Power Agency - FERC 433 - Contract termination date: June 30, 2017.

***Schedule Page: 310.13 Line No.: 5 Column: b***

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

***Schedule Page: 310.13 Line No.: 6 Column: j***

Transmission Losses

***Schedule Page: 310.13 Line No.: 7 Column: j***

Reserve Share

***Schedule Page: 310.13 Line No.: 9 Column: j***

Recognition and reporting of gains and losses on bookouts under EITF Issue No. 03-11.

***Schedule Page: 310.13 Line No.: 10 Column: b***

Settlement Adjustment

***Schedule Page: 310.13 Line No.: 10 Column: j***

Settlement Adjustment

***Schedule Page: 310.13 Line No.: 11 Column: b***

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

***Schedule Page: 310.13 Line No.: 11 Column: j***

The negative revenue reported on this line reflects test energy generated at the Marengo Wind II, Blundell, Goodnoe Hills, Glenrock and Seven Mile Hill 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.: 12 Column: j***

Recognition and reporting of gains and losses on energy trading contracts under EITF Issue No. 02-03.

***Schedule Page: 310.13 Line No.: 13 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 | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

| Line No. | Account (a) | Amount for Current Year (b) | Amount for Previous Year (c) |
|---|---|---|---|
| 1 | 1. POWER PRODUCTION EXPENSES | | |
| 2 | A. Steam Power Generation | | |
| 3 | Operation | | |
| 4 | (500) Operation Supervision and Engineering | 21,838,417 | 21,506,117 |
| 5 | (501) Fuel | 624,912,062 | 581,178,395 |
| 6 | (502) Steam Expenses | 37,487,518 | 33,767,391 |
| 7 | (503) Steam from Other Sources | 3,371,385 | 4,845,079 |
| 8 | (Less) (504) Steam Transferred-Cr. | | |
| 9 | (505) Electric Expenses | 4,303,303 | 4,007,896 |
| 10 | (506) Miscellaneous Steam Power Expenses | 43,572,425 | 41,844,589 |
| 11 | (507) Rents | 281,381 | 859,203 |
| 12 | (509) Allowances | | |
| 13 | TOTAL Operation (Enter Total of Lines 4 thru 12) | 735,766,491 | 688,008,670 |
| 14 | Maintenance | | |
| 15 | (510) Maintenance Supervision and Engineering | 6,008,903 | 6,200,007 |
| 16 | (511) Maintenance of Structures | 24,834,108 | 22,514,293 |
| 17 | (512) Maintenance of Boiler Plant | 86,675,457 | 94,470,112 |
| 18 | (513) Maintenance of Electric Plant | 28,874,080 | 31,838,656 |
| 19 | (514) Maintenance of Miscellaneous Steam Plant | 12,753,101 | 11,951,367 |
| 20 | TOTAL Maintenance (Enter Total of Lines 15 thru 19) | 159,145,649 | 166,974,435 |
| 21 | TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20) | 894,912,140 | 854,983,105 |
| 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 | 8,826,196 | 8,428,491 |
| 45 | (536) Water for Power | 301,387 | 216,788 |
| 46 | (537) Hydraulic Expenses | 4,090,454 | 4,705,966 |
| 47 | (538) Electric Expenses | | |
| 48 | (539) Miscellaneous Hydraulic Power Generation Expenses | 15,930,741 | 13,992,399 |
| 49 | (540) Rents | 141,239 | 45,426 |
| 50 | TOTAL Operation (Enter Total of Lines 44 thru 49) | 29,290,017 | 27,389,070 |
| 51 | C. Hydraulic Power Generation (Continued) | | |
| 52 | Maintenance | | |
| 53 | (541) Mainentance Supervision and Engineering | 2,681 | |
| 54 | (542) Maintenance of Structures | 1,225,169 | 1,020,921 |
| 55 | (543) Maintenance of Reservoirs, Dams, and Waterways | 1,437,284 | 1,017,895 |
| 56 | (544) Maintenance of Electric Plant | 1,572,617 | 1,678,495 |
| 57 | (545) Maintenance of Miscellaneous Hydraulic Plant | 2,151,781 | 2,107,860 |
| 58 | TOTAL Maintenance (Enter Total of lines 53 thru 57) | 6,389,532 | 5,825,171 |
| 59 | TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58) | 35,679,549 | 33,214,241 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

| Line No. | Account<br>(a) | Amount for Current Year<br>(b) | Amount for Previous Year<br>(c) |
|---|---|---|---|
| 60 | D. Other Power Generation | | |
| 61 | Operation | | |
| 62 | (546) Operation Supervision and Engineering | 218,466 | 729,753 |
| 63 | (547) Fuel | 466,962,755 | 325,837,509 |
| 64 | (548) Generation Expenses | 17,845,036 | 22,455,638 |
| 65 | (549) Miscellaneous Other Power Generation Expenses | 10,943,849 | 5,931,466 |
| 66 | (550) Rents | 6,739,843 | 11,964,686 |
| 67 | TOTAL Operation (Enter Total of lines 62 thru 66) | 502,709,949 | 366,919,052 |
| 68 | Maintenance | | |
| 69 | (551) Maintenance Supervision and Engineering | | |
| 70 | (552) Maintenance of Structures | 1,280,348 | 615,974 |
| 71 | (553) Maintenance of Generating and Electric Plant | 5,911,258 | 4,630,669 |
| 72 | (554) Maintenance of Miscellaneous Other Power Generation Plant | 482,926 | 396,083 |
| 73 | TOTAL Maintenance (Enter Total of lines 69 thru 72) | 7,674,532 | 5,642,726 |
| 74 | TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73) | 510,384,481 | 372,561,778 |
| 75 | E. Other Power Supply Expenses | | |
| 76 | (555) Purchased Power | 754,189,849 | 763,738,961 |
| 77 | (556) System Control and Load Dispatching | 1,997,891 | 2,535,080 |
| 78 | (557) Other Expenses | 56,143,944 | 60,542,623 |
| 79 | TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78) | 812,331,684 | 826,816,664 |
| 80 | TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79) | 2,253,307,854 | 2,087,575,788 |
| 81 | 2. TRANSMISSION EXPENSES | | |
| 82 | Operation | | |
| 83 | (560) Operation Supervision and Engineering | 7,808,710 | 8,207,350 |
| 84 | (561) Load Dispatching | | |
| 85 | (561.1) Load Dispatch-Reliability | | |
| 86 | (561.2) Load Dispatch-Monitor and Operate Transmission System | 7,114,390 | 6,335,813 |
| 87 | (561.3) Load Dispatch-Transmission Service and Scheduling | 83,728 | |
| 88 | (561.4) Scheduling, System Control and Dispatch Services | | |
| 89 | (561.5) Reliability, Planning and Standards Development | | |
| 90 | (561.6) Transmission Service Studies | 73,289 | 594,239 |
| 91 | (561.7) Generation Interconnection Studies | 1,264,738 | 958,694 |
| 92 | (561.8) Reliability, Planning and Standards Development Services | | |
| 93 | (562) Station Expenses | 1,869,851 | 1,006,028 |
| 94 | (563) Overhead Lines Expenses | 93,337 | 125,807 |
| 95 | (564) Underground Lines Expenses | | |
| 96 | (565) Transmission of Electricity by Others | 121,167,183 | 106,592,111 |
| 97 | (566) Miscellaneous Transmission Expenses | 1,795,131 | 2,751,804 |
| 98 | (567) Rents | 822,667 | 1,356,267 |
| 99 | TOTAL Operation (Enter Total of lines 83 thru 98) | 142,093,024 | 127,928,113 |
| 100 | Maintenance | | |
| 101 | (568) Maintenance Supervision and Engineering | 9,822 | 56,234 |
| 102 | (569) Maintenance of Structures | 3,284 | 4,076 |
| 103 | (569.1) Maintenance of Computer Hardware | 290,283 | 8,331 |
| 104 | (569.2) Maintenance of Computer Software | 636,171 | 704,405 |
| 105 | (569.3) Maintenance of Communication Equipment | 3,199,160 | 2,516,755 |
| 106 | (569.4) Maintenance of Miscellaneous Regional Transmission Plant | | |
| 107 | (570) Maintenance of Station Equipment | 11,093,119 | 9,272,545 |
| 108 | (571) Maintenance of Overhead Lines | 16,204,998 | 13,323,841 |
| 109 | (572) Maintenance of Underground Lines | | |
| 110 | (573) Maintenance of Miscellaneous Transmission Plant | 480,533 | 380,572 |
| 111 | TOTAL Maintenance (Total of lines 101 thru 110) | 31,917,370 | 26,266,759 |
| 112 | TOTAL Transmission Expenses (Total of lines 99 and 111) | 174,010,394 | 154,194,872 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

| Line No. | Account (a) | Amount for Current Year (b) | Amount for Previous Year (c) |
|---|---|---|---|
| 113 | 3. REGIONAL MARKET EXPENSES | | |
| 114 | Operation | | |
| 115 | (575.1) Operation Supervision | | |
| 116 | (575.2) Day-Ahead and Real-Time Market Facilitation | | |
| 117 | (575.3) Transmission Rights Market Facilitation | | |
| 118 | (575.4) Capacity Market Facilitation | | |
| 119 | (575.5) Ancillary Services Market Facilitation | | |
| 120 | (575.6) Market Monitoring and Compliance | | |
| 121 | (575.7) Market Facilitation, Monitoring and Compliance Services | | |
| 122 | (575.8) Rents | | |
| 123 | Total Operation (Lines 115 thru 122) | | |
| 124 | Maintenance | | |
| 125 | (576.1) Maintenance of Structures and Improvements | | |
| 126 | (576.2) Maintenance of Computer Hardware | | |
| 127 | (576.3) Maintenance of Computer Software | | |
| 128 | (576.4) Maintenance of Communication Equipment | | |
| 129 | (576.5) Maintenance of Miscellaneous Market Operation Plant | | |
| 130 | Total Maintenance (Lines 125 thru 129) | | |
| 131 | TOTAL Regional Transmission and Market Op Expns (Total 123 and 130) | | |
| 132 | 4. DISTRIBUTION EXPENSES | | |
| 133 | Operation | | |
| 134 | (580) Operation Supervision and Engineering | 20,296,814 | 19,728,019 |
| 135 | (581) Load Dispatching | 12,782,671 | 12,661,549 |
| 136 | (582) Station Expenses | 4,574,167 | 3,375,957 |
| 137 | (583) Overhead Line Expenses | 5,392,347 | 7,612,638 |
| 138 | (584) Underground Line Expenses | 403 | 230,535 |
| 139 | (585) Street Lighting and Signal System Expenses | 222,030 | 248,162 |
| 140 | (586) Meter Expenses | 7,204,688 | 5,795,418 |
| 141 | (587) Customer Installations Expenses | 11,063,638 | 9,337,557 |
| 142 | (588) Miscellaneous Expenses | 8,389,281 | 9,098,859 |
| 143 | (589) Rents | 3,038,169 | 4,289,931 |
| 144 | TOTAL Operation (Enter Total of lines 134 thru 143) | 72,964,208 | 72,378,625 |
| 145 | Maintenance | | |
| 146 | (590) Maintenance Supervision and Engineering | 6,421,892 | 6,502,417 |
| 147 | (591) Maintenance of Structures | 2,030,161 | 1,382,792 |
| 148 | (592) Maintenance of Station Equipment | 11,547,226 | 11,743,862 |
| 149 | (593) Maintenance of Overhead Lines | 85,001,337 | 91,506,851 |
| 150 | (594) Maintenance of Underground Lines | 23,539,909 | 22,801,662 |
| 151 | (595) Maintenance of Line Transformers | 1,116,622 | 744,964 |
| 152 | (596) Maintenance of Street Lighting and Signal Systems | 4,138,856 | 4,335,964 |
| 153 | (597) Maintenance of Meters | 5,212,174 | 5,476,485 |
| 154 | (598) Maintenance of Miscellaneous Distribution Plant | 3,391,891 | 4,467,250 |
| 155 | TOTAL Maintenance (Total of lines 146 thru 154) | 142,400,068 | 148,962,247 |
| 156 | TOTAL Distribution Expenses (Total of lines 144 and 155) | 215,364,276 | 221,340,872 |
| 157 | 5. CUSTOMER ACCOUNTS EXPENSES | | |
| 158 | Operation | | |
| 159 | (901) Supervision | 2,477,949 | 2,756,699 |
| 160 | (902) Meter Reading Expenses | 25,289,712 | 28,167,970 |
| 161 | (903) Customer Records and Collection Expenses | 56,637,149 | 55,607,837 |
| 162 | (904) Uncollectible Accounts | 14,674,714 | 8,551,037 |
| 163 | (905) Miscellaneous Customer Accounts Expenses | 229,561 | 374,243 |
| 164 | TOTAL Customer Accounts Expenses (Total of lines 159 thru 163) | 99,309,085 | 95,457,786 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

| Line No. | Account (a) | Amount for Current Year (b) | Amount for Previous Year (c) |
|---|---|---|---|
| 165 | 6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES | | |
| 166 | Operation | | |
| 167 | (907) Supervision | 247,987 | 423,543 |
| 168 | (908) Customer Assistance Expenses | 51,829,080 | 42,756,237 |
| 169 | (909) Informational and Instructional Expenses | 4,101,589 | 3,784,546 |
| 170 | (910) Miscellaneous Customer Service and Informational Expenses | 63,857 | 5,126 |
| 171 | TOTAL Customer Service and Information Expenses (Total 167 thru 170) | 56,242,513 | 46,969,452 |
| 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 | 67,200,789 | 83,301,566 |
| 182 | (921) Office Supplies and Expenses | 11,470,988 | 11,779,729 |
| 183 | (Less) (922) Administrative Expenses Transferred-Credit | 21,538,493 | 20,697,804 |
| 184 | (923) Outside Services Employed | 11,890,876 | 9,800,219 |
| 185 | (924) Property Insurance | 31,882,383 | 24,516,013 |
| 186 | (925) Injuries and Damages | 9,475,122 | 11,291,287 |
| 187 | (926) Employee Pensions and Benefits | | |
| 188 | (927) Franchise Requirements | | |
| 189 | (928) Regulatory Commission Expenses | 11,630,262 | 10,011,639 |
| 190 | (929) (Less) Duplicate Charges-Cr. | 3,987,182 | 5,845,340 |
| 191 | (930.1) General Advertising Expenses | 35,163 | 257,282 |
| 192 | (930.2) Miscellaneous General Expenses | 18,540,495 | 25,310,886 |
| 193 | (931) Rents | 6,318,703 | 6,292,505 |
| 194 | TOTAL Operation (Enter Total of lines 181 thru 193) | 142,919,106 | 156,017,982 |
| 195 | Maintenance | | |
| 196 | (935) Maintenance of General Plant | 27,125,031 | 24,338,489 |
| 197 | TOTAL Administrative & General Expenses (Total of lines 194 and 196) | 170,044,137 | 180,356,471 |
| 198 | TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197) | 2,968,278,259 | 2,785,895,241 |

**Schedule Page: 320 Line No.: 187 Column: b**

Pensions and benefits are charged to functional accounts, which is consistent with where labor is charged. The following table summarizes the pension and benefit expense that was charged to the functional accounts.

| | Years Ended December 31, 2008 | Years Ended December 31, 2007 |
|---|---|---|
| Pension & Benefits Expense | $ 145,242,536 | $ 170,449,274 |

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**(Next Page is 326)**

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Power Purchases | | | | | |
| 2 | AES SeaWest, Inc. | AD | | NA | NA | NA |
| 3 | AES SeaWest, Inc. | LU | | NA | NA | NA |
| 4 | Anaheim, City of | SF | | NA | NA | NA |
| 5 | Arizona Public Service Co. | AD | | NA | NA | NA |
| 6 | Arizona Public Service Co. | LF | | NA | NA | NA |
| 7 | Arizona Public Service Co. | OS | | NA | NA | NA |
| 8 | Arizona Public Service Co. | SF | | NA | NA | NA |
| 9 | Avista Corp. | OS | | NA | NA | NA |
| 10 | Avista Corp. | SF | | NA | NA | NA |
| 11 | BP Energy Company | SF | | NA | NA | NA |
| 12 | Ballard Hog Farms Inc. | LU | | NA | NA | NA |
| 13 | Bank of America, N.A. | SF | | NA | NA | NA |
| 14 | Barclays Bank PLC | AD | | NA | NA | NA |
| | Total | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | COST/SETTLEMENT OF POWER Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | Line No. |
|---|---|---|---|---|---|---|---|
| | | | | | | | 1 |
| | | | | | -271,094 | -271,094 | 2 |
| 156,957 | | | | 5,568,846 | | 5,568,846 | 3 |
| 12,665 | | | | 666,300 | | 666,300 | 4 |
| 26 | | | | | -3,911 | -3,911 | 5 |
| 231,537 | | | | 10,728,296 | | 10,728,296 | 6 |
| 965 | | | | 65,985 | | 65,985 | 7 |
| 47,196 | | | | 2,860,889 | | 2,860,889 | 8 |
| 50 | | | | 3,100 | 875 | 3,975 | 9 |
| 33,998 | | | | 1,511,045 | 21,810 | 1,532,855 | 10 |
| 613,264 | | | | 33,280,594 | 3,767,604 | 37,048,198 | 11 |
| 72 | | | | 2,183 | | 2,183 | 12 |
| | | | | | -290,932 | -290,932 | 13 |
| 625 | | | | | 43,156 | 43,156 | 14 |
| 11,909,498 | 6,436,684 | 6,569,511 | 135,972,332 | 1,556,826,346 | -938,608,829 | 754,189,849 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original (2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Barclays Bank PLC | SF | | NA | NA | NA |
| 2 | Bear Energy LP | SF | | NA | NA | NA |
| 3 | Beaver City | LF | | NA | NA | NA |
| 4 | Bell Mountain Power | LU | | NA | NA | NA |
| 5 | Benton County Pub Utility Dist No.1 | SF | | NA | NA | NA |
| 6 | Biomass One, L.P. | LU | | 22.5 | 17.6 | 15.3 |
| 7 | Birch Creek Hydro | LU | | NA | NA | NA |
| 8 | Black Hills Power, Inc. | AD | | NA | NA | NA |
| 9 | Black Hills Power, Inc. | LU | | NA | NA | NA |
| 10 | Black Hills Power, Inc. | OS | | NA | NA | NA |
| 11 | Black Hills Power, Inc. | SF | | NA | NA | NA |
| 12 | Black Hills Wyoming, Inc. | OS | | NA | NA | NA |
| 13 | Black Hills Wyoming, Inc. | SF | | NA | NA | NA |
| 14 | Blanding City | LF | | NA | NA | NA |
| | Total | | | | | |

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 1,528,205 | | | | 96,158,784 | -5,959,354 | 90,199,430 | 1 |
| 97,726 | | | | 6,041,008 | -2,085,148 | 3,955,860 | 2 |
| 64 | | | | 5,369 | | 5,369 | 3 |
| 1,000 | | | | 48,488 | | 48,488 | 4 |
| 13,900 | | | | 1,009,100 | | 1,009,100 | 5 |
| 127,002 | | | 2,399,625 | 16,826,609 | 4,266,275 | 23,492,509 | 6 |
| 10,180 | | | | 546,163 | | 546,163 | 7 |
| -1 | | | | | 33,725 | 33,725 | 8 |
| 1,239 | | | | | 2,189,418 | 2,189,418 | 9 |
| 563 | | | | 60,084 | | 60,084 | 10 |
| 87,621 | | | | 5,243,188 | | 5,243,188 | 11 |
| 910 | | | | 123,200 | | 123,200 | 12 |
| 320 | | | | 33,560 | | 33,560 | 13 |
| 391 | | | | 29,343 | | 29,343 | 14 |
| 11,909,498 | 6,436,684 | 6,569,511 | 135,972,332 | 1,556,826,346 | -938,608,829 | 754,189,849 | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classifi-cation (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Bogus Creek | LU | | NA | NA | NA |
| 2 | Bonneville Power Administration | AD | | NA | NA | NA |
| 3 | Bonneville Power Administration | LF | | 575 | 575 | 497 |
| 4 | Bonneville Power Administration | LF | | NA | NA | NA |
| 5 | Bonneville Power Administration | OS | | NA | NA | NA |
| 6 | Bonneville Power Administration | SF | | NA | NA | NA |
| 7 | Burbank, City of | SF | | NA | NA | NA |
| 8 | CDM Hydro | LU | | NA | NA | NA |
| 9 | California Independent System Operator | AD | | NA | NA | NA |
| 10 | California Independent System Operator | SF | | NA | NA | NA |
| 11 | Cargill Power Markets, LLC | AD | | NA | NA | NA |
| 12 | Cargill Power Markets, LLC | OS | | NA | NA | NA |
| 13 | Cargill Power Markets, LLC | SF | | NA | NA | NA |
| 14 | Central Oregon Irrigation District | AD | | NA | NA | NA |
| | Total | | | | | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 936 | | | | 31,714 | | 31,714 | 1 |
| | | | | | 68,398 | 68,398 | 2 |
| | | | 47,058,000 | | | 47,058,000 | 3 |
| | | | | | 1,538,270 | 1,538,270 | 4 |
| | | | | | 282,893 | 282,893 | 5 |
| 314,754 | | | | 14,177,016 | 234,806 | 14,411,822 | 6 |
| 30,673 | | | | 1,848,770 | | 1,848,770 | 7 |
| 28,251 | | | | 1,508,386 | | 1,508,386 | 8 |
| 4,686 | | | | | 291,087 | 291,087 | 9 |
| 267,714 | | | | 15,001,833 | | 15,001,833 | 10 |
| 1,083 | | | | | 108,051 | 108,051 | 11 |
| 18,663 | | | | 991,196 | | 991,196 | 12 |
| 841,937 | | | | 51,558,968 | | 51,558,968 | 13 |
| | | | | | -21,957 | -21,957 | 14 |
| 11,909,498 | 6,436,684 | 6,569,511 | 135,972,332 | 1,556,826,346 | -938,608,829 | 754,189,849 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Central Oregon Irrigation District | LU | | 3.3 | 3.3 | 2.1 |
| 2 | Chelan County Pub Utility Dist No. 1 | LU | | NA | NA | NA |
| 3 | Chelan County Pub Utility Dist No. 1 | OS | | NA | NA | NA |
| 4 | Chelan County Pub Utility Dist No. 1 | SF | | NA | NA | NA |
| 5 | Citigroup Energy, Inc. | AD | | NA | NA | NA |
| 6 | Citigroup Energy, Inc. | SF | | NA | NA | NA |
| 7 | City of Buffalo | LU | | 0.2 | 0.2 | 0.2 |
| 8 | Clatskanie People's Utility District | SF | | NA | NA | NA |
| 9 | Colorado River Commission of Nevada | AD | | NA | NA | NA |
| 10 | Commercial Energy Management | LU | | NA | NA | NA |
| 11 | Conoco Inc. | OS | | NA | NA | NA |
| 12 | Conoco Inc. | SF | | NA | NA | NA |
| 13 | Constellation Energy Commodities Group | AD | | NA | NA | NA |
| 14 | Constellation Energy Commodities Group | OS | | NA | NA | NA |
| | Total | | | | | |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 20,364 | | | 338,635 | 1,822,588 | | 2,161,223 | 1 |
| 424,675 | | | | | 3,831,387 | 3,831,387 | 2 |
| | | | | | 200 | 200 | 3 |
| 22,716 | | | | 1,131,560 | 6,988 | 1,138,548 | 4 |
| -11 | | | | | -405 | -405 | 5 |
| 1,170,638 | | | | 73,264,167 | 1,861,808 | 75,125,975 | 6 |
| 1,813 | | | 27,123 | 137,758 | | 164,881 | 7 |
| 1,170 | | | | 55,110 | | 55,110 | 8 |
| 51 | | | | | 9,372 | 9,372 | 9 |
| 1,372 | | | | 70,963 | | 70,963 | 10 |
| 600 | | | | 45,250 | | 45,250 | 11 |
| 352,594 | | | | 24,852,826 | | 24,852,826 | 12 |
| 1,173 | | | | | 75,269 | 75,269 | 13 |
| 4,073 | | | | 379,205 | | 379,205 | 14 |
| 11,909,498 | 6,436,684 | 6,569,511 | 135,972,332 | 1,556,826,346 | -938,608,829 | 754,189,849 | |

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Constellation Energy Commodities Group | SF | | 150 | NA | NA |
| 2 | Cowlitz County Pub Utility Dist No.1 | OS | | NA | NA | NA |
| 3 | Credit Suisse Energy LLC | AD | | NA | NA | NA |
| 4 | Credit Suisse Energy LLC | SF | | NA | NA | NA |
| 5 | Curtiss Livestock | LU | | NA | NA | NA |
| 6 | DB Energy Trading LLC | AD | | NA | NA | NA |
| 7 | DB Energy Trading LLC | SF | | NA | NA | NA |
| 8 | DR Johnson Lumber Company | LU | | NA | NA | NA |
| 9 | Davis County Waste Management | LU | | NA | NA | NA |
| 10 | Deschutes Valley Water District | LU | | 5.8 | 4.0 | 3.0 |
| 11 | Deseret Power Electric Cooperative | LF | | 100 | 100 | 99 |
| 12 | Desert Power, L.P. | LU | | NA | NA | NA |
| 13 | Deutsche Bank AG | SF | | NA | NA | NA |
| 14 | Douglas County Forest Products | IU | | NA | NA | NA |
| | Total | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | COST/SETTLEMENT OF POWER Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | Line No. |
|---|---|---|---|---|---|---|---|
| 1,154,547 | | | 3,832,200 | 80,121,573 | 2,937,732 | 86,891,505 | 1 |
| | | | | | -495,391 | -495,391 | 2 |
| 289 | | | | | 18,601 | 18,601 | 3 |
| 653,581 | | | | 47,880,241 | -4,520,033 | 43,360,208 | 4 |
| 99 | | | | 6,375 | | 6,375 | 5 |
| | | | | | 5,232 | 5,232 | 6 |
| 309,012 | | | | 17,455,734 | | 17,455,734 | 7 |
| 65,884 | | | | 4,275,730 | | 4,275,730 | 8 |
| 458 | | | | 24,062 | | 24,062 | 9 |
| 29,105 | | | 567,311 | 2,939,621 | | 3,506,932 | 10 |
| 817,812 | | | 13,486,104 | 14,061,389 | 3,566,662 | 31,114,155 | 11 |
| | | | | | -500,000 | -500,000 | 12 |
| | | | | | -2,484,519 | -2,484,519 | 13 |
| 821 | | | | 44,018 | | 44,018 | 14 |
| 11,909,498 | 6,436,684 | 6,569,511 | 135,972,332 | 1,556,826,346 | -938,608,829 | 754,189,849 | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Douglas County Pub Utility Dist No. 1 | AD | | NA | NA | NA |
| 2 | Douglas County Pub Utility Dist No. 1 | AD | | NA | NA | NA |
| 3 | Douglas County Pub Utility Dist No. 1 | LU | | NA | NA | NA |
| 4 | Douglas County Pub Utility Dist No. 1 | OS | | NA | NA | NA |
| 5 | Douglas County Pub Utility Dist No. 1 | SF | | NA | NA | NA |
| 6 | Draper Irrigation Company | IU | | NA | NA | NA |
| 7 | Dry Creek | AD | | NA | NA | NA |
| 8 | Dry Creek | LU | | NA | NA | NA |
| 9 | Dynegy Power Marketing | AD | | NA | NA | NA |
| 10 | Dynegy Power Marketing | SF | | NA | NA | NA |
| 11 | EPCOR Energy Marketing (U.S.) Inc. | SF | | NA | NA | NA |
| 12 | Eagle Point Irrigation District | LU | | 0.8 | 0.6 | 0.4 |
| 13 | El Paso Electric Company | SF | | NA | NA | NA |
| 14 | Eugene Water & Electric Board | SF | | NA | NA | NA |
| | Total | | | | | |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| | | | | | -52,263 | -52,263 | 1 |
| | | | | | -72,365 | -72,365 | 2 |
| 339,320 | | | | | 2,665,274 | 2,665,274 | 3 |
| 52,699 | | | | 1,011,382 | 6,454,000 | 7,465,382 | 4 |
| 23,449 | | | | 1,483,835 | 1,646 | 1,485,481 | 5 |
| 290 | | | | 15,870 | | 15,870 | 6 |
| 61 | | | | | 3,591 | 3,591 | 7 |
| 9,830 | | | | 488,534 | | 488,534 | 8 |
| 25 | | | | | 1,594 | 1,594 | 9 |
| 42,988 | | | | 3,046,188 | | 3,046,188 | 10 |
| 22,000 | | | | 1,658,576 | | 1,658,576 | 11 |
| 2,842 | | | 38,555 | 301,546 | | 340,101 | 12 |
| 71,528 | | | | 4,081,052 | 9,467 | 4,090,519 | 13 |
| 122,165 | | | | 6,428,246 | | 6,428,246 | 14 |
| 11,909,498 | 6,436,684 | 6,569,511 | 135,972,332 | 1,556,826,346 | -938,608,829 | 754,189,849 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Eurus Energy America | LU | | NA | NA | NA |
| 2 | Evergreen BioPower, LLC | AD | | NA | NA | NA |
| 3 | Evergreen BioPower, LLC | LU | | NA | NA | NA |
| 4 | ExxonMobile Production Company | LU | | NA | NA | NA |
| 5 | FPL Energy Power Marketing, Inc. | SF | | NA | NA | NA |
| 6 | Falls Creek | LU | | 3.0 | 3.3 | 2.0 |
| 7 | Farmers Irrigation District | LU | | 3.8 | 3.3 | 2.6 |
| 8 | Fery, Loyd | LU | | NA | NA | NA |
| 9 | Fillmore City | LF | | NA | NA | NA |
| 10 | Finley BioEnergy, LLC | AD | | NA | NA | NA |
| 11 | Finley BioEnergy, LLC | LU | | NA | NA | NA |
| 12 | Fortis Energy Marketing & Trading GP | AD | | NA | NA | NA |
| 13 | Fortis Energy Marketing & Trading GP | SF | | NA | NA | NA |
| 14 | Franklin County Pub Utility Dist No. 1 | SF | | NA | NA | NA |
| | Total | | | | | |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 114,457 | | | | 4,891,895 | | 4,891,895 | 1 |
| | | | | | 11 | 11 | 2 |
| 39,472 | | | | 2,057,082 | | 2,057,082 | 3 |
| 646,083 | | | | 32,481,542 | | 32,481,542 | 4 |
| 40,400 | | | | 2,756,650 | | 2,756,650 | 5 |
| 15,926 | | | 194,348 | 1,579,878 | | 1,774,226 | 6 |
| 22,794 | | | 327,533 | 2,279,430 | | 2,606,963 | 7 |
| 265 | | | | 17,113 | | 17,113 | 8 |
| 182 | | | | 19,680 | | 19,680 | 9 |
| | | | | | | | 10 |
| 25,596 | | | | 1,649,745 | | 1,649,745 | 11 |
| 50 | | | | | 3,450 | 3,450 | 12 |
| 182,462 | | | | 11,497,101 | 1,411,432 | 12,908,533 | 13 |
| 8,670 | | | | 612,475 | | 612,475 | 14 |
| 11,909,498 | 6,436,684 | 6,569,511 | 135,972,332 | 1,556,826,346 | -938,608,829 | 754,189,849 | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Frito Lay | OS | | NA | NA | NA |
| 2 | Galesville Dam | LU | | 0.6 | 0.9 | 0.6 |
| 3 | Garland Canal | LU | | 2.5 | 1.4 | 1.2 |
| 4 | General Chemical Corporation | OS | | 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 | Grand Valley Power | LF | | NA | NA | NA |
| 10 | Grant County Pub Utility Dist No. 2 | AD | | NA | NA | NA |
| 11 | Grant County Pub Utility Dist No. 2 | LF | | 14 | NA | NA |
| 12 | Grant County Pub Utility Dist No. 2 | LU | | NA | NA | NA |
| 13 | Grant County Pub Utility Dist No. 2 | LU | | NA | NA | NA |
| 14 | Grant County Pub Utility Dist No. 2 | OS | | NA | NA | NA |
| | Total | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES: MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | COST/SETTLEMENT OF POWER: Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | Line No. |
|---|---|---|---|---|---|---|---|
| | | | | | 612 | 612 | 1 |
| 5,457 | | | 68,315 | 616,642 | | 684,957 | 2 |
| 9,726 | | | 151,675 | 369,787 | | 521,462 | 3 |
| 1,343 | | | | 20,004 | | 20,004 | 4 |
| 7,441 | | | | 389,930 | | 389,930 | 5 |
| 1,815 | | | | 94,593 | | 94,593 | 6 |
| 135 | | | | 4,550 | | 4,550 | 7 |
| 173,287 | | | | 7,879,980 | | 7,879,980 | 8 |
| 83 | | | | 13,298 | | 13,298 | 9 |
| | | | | | -1,409,695 | -1,409,695 | 10 |
| 87,600 | | | 87,093 | 6,402,318 | 331,753 | 6,821,164 | 11 |
| 1,263,255 | | | | 11,672,998 | 12,764,527 | 24,437,525 | 12 |
| 272,098 | | | | | 12,514,788 | 12,514,788 | 13 |
| | | | | | 4,940 | 4,940 | 14 |
| 11,909,498 | 6,436,684 | 6,569,511 | 135,972,332 | 1,556,826,346 | -938,608,829 | 754,189,849 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Grant County Pub Utility Dist No. 2 | SF | | NA | NA | NA |
| 2 | Grays Harbor Public Utility District | SF | | NA | NA | NA |
| 3 | Heber Light & Power Company | LF | | NA | NA | NA |
| 4 | Hermiston Generating Company, L.P. | AD | | NA | NA | NA |
| 5 | Hermiston Generating Company, L.P. | LU | | 241 | 241 | 198 |
| 6 | Highland Energy LLC | SF | | NA | NA | NA |
| 7 | Hill Air Force Base | LU | | NA | NA | NA |
| 8 | Hurricane, City of | LF | | NA | NA | NA |
| 9 | Iberdrola Renewables, Inc. | OS | | NA | NA | NA |
| 10 | Iberdrola Renewables, Inc. | SF | | NA | NA | NA |
| 11 | Idaho Falls, City of | AD | | NA | NA | NA |
| 12 | Idaho Falls, City of | LU | | NA | NA | NA |
| 13 | Idaho Power Company | SF | | NA | NA | NA |
| 14 | Idaho Power Company | SF | | NA | NA | NA |
| | Total | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 19,319 | | | | 1,073,515 | 6,581 | 1,080,096 | 1 |
| 5,950 | | | | 429,285 | | 429,285 | 2 |
| 5,909 | | | | 467,076 | | 467,076 | 3 |
| 9,961 | | | | | -434,786 | -434,786 | 4 |
| 1,801,380 | | | 34,630,139 | 57,797,389 | 354,652 | 92,782,180 | 5 |
| 60,204 | | | | 4,174,049 | | 4,174,049 | 6 |
| 7,710 | | | | 346,455 | | 346,455 | 7 |
| 1,802 | | | | 135,135 | | 135,135 | 8 |
| 160 | | | | 2,080 | | 2,080 | 9 |
| 410,878 | | | | 21,505,163 | -4,811,012 | 16,694,151 | 10 |
| | | | | | 19,242 | 19,242 | 11 |
| 48,160 | | | | | 2,741,428 | 2,741,428 | 12 |
| 26,377 | | | | | 1,966,281 | 1,966,281 | 13 |
| 34,942 | | | | 1,996,395 | 19,014 | 2,015,409 | 14 |
| 11,909,498 | 6,436,684 | 6,569,511 | 135,972,332 | 1,556,826,346 | -938,608,829 | 754,189,849 | |

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Integrys Energy Services, Inc. | SF | | NA | NA | NA |
| 2 | Intermountain Power Project | LU | | NA | NA | NA |
| 3 | International Paper Company | OS | | NA | NA | NA |
| 4 | J. Aron & Company | AD | | NA | NA | NA |
| 5 | J. Aron & Company | SF | | NA | NA | NA |
| 6 | J.P. Morgan Ventures Energy Corp. | SF | | NA | NA | NA |
| 7 | Kennecott | IU | | NA | NA | NA |
| 8 | Kennecott | LU | | NA | NA | NA |
| 9 | L&M Angus Ranch, LLC | LU | | NA | NA | NA |
| 10 | Lacomb Irrigation | LU | | NA | NA | NA |
| 11 | Lake Siskiyou | LU | | 1.9 | 2.7 | 1.3 |
| 12 | Lehman Brothers Commodity Services | SF | | NA | NA | NA |
| 13 | Logan City | OS | | NA | NA | NA |
| 14 | Los Angeles Dept. of Water & Power | OS | | NA | NA | NA |
| | Total | | | | | |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 7,350 | | | | 417,510 | | 417,510 | 1 |
| 582,894 | | | | 25,898,987 | | 25,898,987 | 2 |
| 160,345 | | | | 10,632,666 | | 10,632,666 | 3 |
| | | | | | -16 | -16 | 4 |
| 297,542 | | | | 18,868,012 | 2,883,311 | 21,751,323 | 5 |
| 83,932 | | | | 5,607,037 | 2,649,510 | 8,256,547 | 6 |
| 157,659 | | | | 6,657,606 | | 6,657,606 | 7 |
| | | | | | 10,127,010 | 10,127,010 | 8 |
| 1,723 | | | | 92,072 | | 92,072 | 9 |
| 4,990 | | | | 346,776 | 31,942 | 378,718 | 10 |
| 12,313 | | | 178,960 | 1,296,171 | | 1,475,131 | 11 |
| 159,200 | | | | 11,338,180 | 772,832 | 12,111,012 | 12 |
| 29 | | | | 3,376 | | 3,376 | 13 |
| 14,047 | | | | 588,473 | 187,330 | 775,803 | 14 |
| 11,909,498 | 6,436,684 | 6,569,511 | 135,972,332 | 1,556,826,346 | -938,608,829 | 754,189,849 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Los Angeles Dept. of Water & Power | SF | | NA | NA | NA |
| 2 | Louis Dreyfus Energy Services L.P. | SF | | NA | NA | NA |
| 3 | Luckey, Paul | LU | | NA | NA | NA |
| 4 | Macquarie Cook Power Inc. | SF | | NA | NA | NA |
| 5 | Magnesium Corporation of America | IU | | NA | NA | NA |
| 6 | Magnesium Corporation of America | LF | | NA | NA | NA |
| 7 | Marsh Valley Hydro & Electric Company | AD | | NA | NA | NA |
| 8 | Marsh Valley Hydro & Electric Company | LU | | NA | NA | NA |
| 9 | Merrill Lynch Commodities, Inc. | SF | | NA | NA | NA |
| 10 | Middlefork Irrigation District | AD | | NA | NA | NA |
| 11 | Middlefork Irrigation District | LU | | NA | NA | NA |
| 12 | Mink Creek Hydro | LU | | NA | NA | NA |
| 13 | Mirant Americas Energy Marketing, L.P. | SF | | NA | NA | NA |
| 14 | Monsanto | IU | | NA | NA | NA |
| | Total | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES MegaWatt Hours Received (h) | POWER EXCHANGES MegaWatt Hours Delivered (i) | COST/SETTLEMENT OF POWER Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | Line No. |
|---|---|---|---|---|---|---|---|
| 25,080 | | | | 2,452,890 | 1,401 | 2,454,291 | 1 |
| 750 | | | | 69,750 | | 69,750 | 2 |
| 286 | | | | 31,542 | | 31,542 | 3 |
| 3,600 | | | | 204,936 | | 204,936 | 4 |
| 245,726 | | | | 14,848,123 | | 14,848,123 | 5 |
| | | | | | 1,755,360 | 1,755,360 | 6 |
| -9 | | | | | -809 | -809 | 7 |
| 3,929 | | | | 209,340 | | 209,340 | 8 |
| 68,125 | | | | 5,055,770 | 613,894 | 5,669,664 | 9 |
| | | | | | -25,873 | -25,873 | 10 |
| 25,178 | | | | 1,325,380 | | 1,325,380 | 11 |
| 9,286 | | | | 480,614 | | 480,614 | 12 |
| 172 | | | | 1,875 | | 1,875 | 13 |
| | | | | | 15,862,455 | 15,862,455 | 14 |
| 11,909,498 | 6,436,684 | 6,569,511 | 135,972,332 | 1,556,826,346 | -938,608,829 | 754,189,849 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Morgan City | LF | | NA | NA | NA |
| 2 | Morgan Stanley Capital Group, Inc. | AD | | NA | NA | NA |
| 3 | Morgan Stanley Capital Group, Inc. | IF | | NA | NA | NA |
| 4 | Morgan Stanley Capital Group, Inc. | SF | | NA | NA | NA |
| 5 | Mountain Energy, Inc. | LU | | NA | NA | NA |
| 6 | Mountain Wind Power II, LLC | LU | | NA | NA | NA |
| 7 | Mountain Wind Power, LLC | LU | | NA | NA | NA |
| 8 | Municipal Energy Agency of Nebraska | SF | | NA | NA | NA |
| 9 | Nephi City | LF | | NA | NA | NA |
| 10 | Nevada Power Company | SF | | NA | NA | NA |
| 11 | Nicholson Sunnybar Ranch | LU | | NA | NA | NA |
| 12 | North Fork Sprague | LU | | 0.4 | 0.5 | 0.2 |
| 13 | NorthWestern Energy | SF | | NA | NA | NA |
| 14 | Northern California Power Agency | SF | | NA | NA | NA |
| | Total | | | | | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 28 | | | | 3,087 | | 3,087 | 1 |
| 907 | | | | | 38,593 | 38,593 | 2 |
| 329,581 | | | | 17,743,814 | | 17,743,814 | 3 |
| 2,863,639 | | | | 191,715,364 | 2,540,176 | 194,255,540 | 4 |
| 56 | | | | 3,580 | | 3,580 | 5 |
| 57,375 | | | | 3,057,399 | | 3,057,399 | 6 |
| 77,658 | | | | 3,892,949 | | 3,892,949 | 7 |
| 240 | | | | 18,240 | | 18,240 | 8 |
| 14 | | | | 1,468 | | 1,468 | 9 |
| 23,709 | | | | 707,345 | 921,198 | 1,628,543 | 10 |
| 1,472 | | | | 76,192 | | 76,192 | 11 |
| 2,460 | | | 38,963 | 256,119 | | 295,082 | 12 |
| 410 | | | | | 24,904 | 24,904 | 13 |
| 4,040 | | | | 332,440 | | 332,440 | 14 |
| 11,909,498 | 6,436,684 | 6,569,511 | 135,972,332 | 1,556,826,346 | -938,608,829 | 754,189,849 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Northpoint Energy Solutions Inc. | SF | | NA | NA | NA |
| 2 | Nucor Corporation | IF | | NA | NA | NA |
| 3 | O.J. Power Company | LU | | NA | NA | NA |
| 4 | Occidental Power Services, Inc. | SF | | NA | NA | NA |
| 5 | Odell Creek | LU | | 0.05 | 0.06 | 0.04 |
| 6 | Oregon Environmental Industries, LLC | LU | | NA | NA | NA |
| 7 | PPL EnergyPlus, LLC | OS | | NA | NA | NA |
| 8 | PPL EnergyPlus, LLC | SF | | NA | NA | NA |
| 9 | Pacific Gas & Electric Company | SF | | NA | NA | NA |
| 10 | Pacific NW Generating Cooperative | SF | | NA | NA | NA |
| 11 | Pacific Summit Energy LLC | SF | | NA | NA | NA |
| 12 | Pasadena, City of | OS | | NA | NA | NA |
| 13 | Pasadena, City of | SF | | NA | NA | NA |
| 14 | Payson City Corporation | LF | | NA | NA | NA |
| | Total | | | | | |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | COST/SETTLEMENT OF POWER Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | Line No. |
|---|---|---|---|---|---|---|---|
| 31,478 | | | | 2,063,484 | | 2,063,484 | 1 |
| | | | | | 4,610,400 | 4,610,400 | 2 |
| 675 | | | | 32,523 | | 32,523 | 3 |
| 13,520 | | | | 1,265,360 | | 1,265,360 | 4 |
| 307 | | | 4,472 | 28,020 | | 32,492 | 5 |
| 21,802 | | | | 1,125,844 | | 1,125,844 | 6 |
| 38 | | | | 1,444 | | 1,444 | 7 |
| 3,165 | | | | 180,340 | | 180,340 | 8 |
| 8,605 | | | | 846,940 | | 846,940 | 9 |
| 12,750 | | | | 677,680 | | 677,680 | 10 |
| 137,030 | | | | 8,551,540 | | 8,551,540 | 11 |
| 5,339 | | | | 197,758 | | 197,758 | 12 |
| 1,601 | | | | 141,198 | | 141,198 | 13 |
| 8 | | | | 1,030 | | 1,030 | 14 |
| 11,909,498 | 6,436,684 | 6,569,511 | 135,972,332 | 1,556,826,346 | -938,608,829 | 754,189,849 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Pinnacle West Marketing & Trading Co. | SF | | NA | NA | NA |
| 2 | Platte River Power | AD | | NA | NA | NA |
| 3 | Platte River Power | SF | | NA | NA | NA |
| 4 | Portland General Electric Co. | AD | | NA | NA | NA |
| 5 | Portland General Electric Co. | LF | | NA | NA | NA |
| 6 | Portland General Electric Co. | OS | | NA | NA | NA |
| 7 | Portland General Electric Co. | SF | | NA | NA | NA |
| 8 | Powerex | AD | | NA | NA | NA |
| 9 | Powerex | SF | | NA | NA | NA |
| 10 | Praxair | OS | | NA | NA | NA |
| 11 | Preston City Hydro | LU | | NA | NA | NA |
| 12 | Provo City | LF | | NA | NA | NA |
| 13 | Public Service Company of Colorado | AD | | NA | NA | NA |
| 14 | Public Service Company of Colorado | SF | | NA | NA | NA |
| | Total | | | | | |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | COST/SETTLEMENT OF POWER Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | Line No. |
|---|---|---|---|---|---|---|---|
| 79 | | | | 6,685 | | 6,685 | 1 |
| -25 | | | | | -1,316 | -1,316 | 2 |
| 3,439 | | | | | 189,491 | 189,491 | 3 |
| | | | | | 363,063 | 363,063 | 4 |
| 12,024 | | | | | 252,000 | 252,000 | 5 |
| | | | | | 1,800 | 1,800 | 6 |
| 191,774 | | | | 9,781,009 | 31,214 | 9,812,223 | 7 |
| 386 | | | | | 20,760 | 20,760 | 8 |
| 571,986 | | | | 39,095,215 | | 39,095,215 | 9 |
| | | | | | 2,953 | 2,953 | 10 |
| 2,445 | | | | 118,685 | | 118,685 | 11 |
| 156 | | | | 12,400 | | 12,400 | 12 |
| 60 | | | | | 2,807 | 2,807 | 13 |
| 30,629 | | | | 1,811,201 | | 1,811,201 | 14 |
| 11,909,498 | 6,436,684 | 6,569,511 | 135,972,332 | 1,556,826,346 | -938,608,829 | 754,189,849 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Public Service Company of New Mexico | AD | | NA | NA | NA |
| 2 | Public Service Company of New Mexico | OS | | NA | NA | NA |
| 3 | Public Service Company of New Mexico | SF | | NA | NA | NA |
| 4 | Pub Utility Dist No.1 of Lewis County | LF | | NA | NA | NA |
| 5 | Puget Sound Energy | SF | | NA | NA | NA |
| 6 | Puget Sound Energy | SF | | NA | NA | NA |
| 7 | Quail Mountain, Inc. | AD | | NA | NA | NA |
| 8 | Rainbow Energy Marketing | SF | | NA | NA | NA |
| 9 | Ralphs Ranch, Inc. | LU | | NA | NA | NA |
| 10 | Redding, City of | SF | | NA | NA | NA |
| 11 | Reliant Energy Services, Inc. | SF | | NA | NA | NA |
| 12 | Riverside, City of | OS | | NA | NA | NA |
| 13 | Riverside, City of | SF | | NA | NA | NA |
| 14 | Rocky Mountain Generation Cooperative | OS | | NA | NA | NA |
| | Total | | | | | |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 309 | | | | | 18,226 | 18,226 | 1 |
| 365 | | | | 26,125 | | 26,125 | 2 |
| 151,352 | | | | 9,587,416 | 262,472 | 9,849,888 | 3 |
| | | | | 34,828 | | 34,828 | 4 |
| | | | | | 110,531 | 110,531 | 5 |
| 122,205 | | | | 6,608,853 | 31,299 | 6,640,152 | 6 |
| | | | | | 10 | 10 | 7 |
| 24,461 | | | | 1,371,338 | | 1,371,338 | 8 |
| 240 | | | | 26,792 | | 26,792 | 9 |
| 1,000 | | | | 40,952 | | 40,952 | 10 |
| 27,500 | | | | 2,489,700 | | 2,489,700 | 11 |
| 39,586 | | | | 1,455,741 | | 1,455,741 | 12 |
| 48 | | | | 2,088 | | 2,088 | 13 |
| 135 | | | | 6,975 | | 6,975 | 14 |
| 11,909,498 | 6,436,684 | 6,569,511 | 135,972,332 | 1,556,826,346 | -938,608,829 | 754,189,849 | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Rocky Mountain Generation Cooperative | SF | | NA | NA | NA |
| 2 | Roseburg Forest Products Co. | LU | | NA | NA | NA |
| 3 | Rough & Ready Lumber Company | LU | | NA | NA | NA |
| 4 | Roush Hydro, Inc. | LU | | NA | NA | NA |
| 5 | SUEZ Energy Marketing NA, Inc. | SF | | 525 | 458 | 474 |
| 6 | Sacramento Municipal Utility District | AD | | NA | NA | NA |
| 7 | Sacramento Municipal Utility District | LF | | NA | NA | NA |
| 8 | Sacramento Municipal Utility District | SF | | NA | NA | NA |
| 9 | Salt River Project | OS | | NA | NA | NA |
| 10 | Salt River Project | SF | | NA | NA | NA |
| 11 | San Diego Gas & Electric | AD | | NA | NA | NA |
| 12 | San Diego Gas & Electric | SF | | NA | NA | NA |
| 13 | Santa Clara, City of | SF | | NA | NA | NA |
| 14 | Santiam Water Control District | LU | | 0.2 | 0.001 | 0.0 |
| | Total | | | | | |

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 5,250 | | | | 212,066 | | 212,066 | 1 |
| 138,294 | | | | 7,896,563 | -169,990 | 7,726,573 | 2 |
| 6,337 | | | | 409,381 | | 409,381 | 3 |
| 273 | | | | 17,687 | | 17,687 | 4 |
| 1,236,248 | | | 11,508,744 | 79,977,920 | 4,685,077 | 96,171,741 | 5 |
| | | | | | 156,389 | 156,389 | 6 |
| 218,868 | | | | 3,250,190 | | 3,250,190 | 7 |
| 35,584 | | | | 2,795,932 | | 2,795,932 | 8 |
| 3,480 | | | | 285,360 | | 285,360 | 9 |
| 186,463 | | | | 11,174,082 | 3,129 | 11,177,211 | 10 |
| -6 | | | | | -372 | -372 | 11 |
| 26,495 | | | | 1,701,165 | | 1,701,165 | 12 |
| 6,854 | | | | 447,950 | | 447,950 | 13 |
| 1,571 | | | 13,632 | 140,183 | | 153,815 | 14 |
| 11,909,498 | 6,436,684 | 6,569,511 | 135,972,332 | 1,556,826,346 | -938,608,829 | 754,189,849 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Schwendiman Wind Farms Inc. | LU | | NA | NA | NA |
| 2 | Seattle City Light | SF | | NA | NA | NA |
| 3 | Sempra Energy Solutions | SF | | NA | NA | NA |
| 4 | Sempra Energy Trading LLC | AD | | NA | NA | NA |
| 5 | Sempra Energy Trading LLC | SF | | NA | NA | NA |
| 6 | Sempra Generation | SF | | NA | NA | NA |
| 7 | Shell Energy North America (US), L.P. | AD | | NA | NA | NA |
| 8 | Shell Energy North America (US), L.P. | OS | | NA | NA | NA |
| 9 | Shell Energy North America (US), L.P. | SF | | NA | NA | NA |
| 10 | Sierra Pacific Power Company | SF | | NA | NA | NA |
| 11 | Simplot Phosphates, LLC | LU | | 10 | 12 | 9 |
| 12 | Simplot Phosphates, LLC | OS | | NA | NA | NA |
| 13 | Slate Creek | LU | | 2.4 | 1.8 | 0.8 |
| 14 | Snohomish Pub Utility Dist No. 1 | SF | | NA | NA | NA |
| | Total | | | | | |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | COST/SETTLEMENT OF POWER Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | Line No. |
|---|---|---|---|---|---|---|---|
| | | | | | -440,462 | -440,462 | 1 |
| 83,783 | | | | 5,073,461 | 13,799 | 5,087,260 | 2 |
| 25,864 | | | | 1,775,347 | | 1,775,347 | 3 |
| 223 | | | | | 12,675 | 12,675 | 4 |
| 1,477,181 | | | | 96,231,315 | -2,211,661 | 94,019,654 | 5 |
| 14,767 | | | | 995,926 | | 995,926 | 6 |
| -175 | | | | | -12,705 | -12,705 | 7 |
| 839 | | | | 44,592 | | 44,592 | 8 |
| 588,229 | | | | 36,965,666 | -852,718 | 36,112,948 | 9 |
| 46,886 | | | | 3,259,482 | 46,949 | 3,306,431 | 10 |
| 76,472 | | | 444,600 | 3,139,924 | | 3,584,524 | 11 |
| | | | | | 8,801 | 8,801 | 12 |
| 8,635 | | | 125,995 | 803,062 | | 929,057 | 13 |
| 53,969 | | | | 2,374,311 | | 2,374,311 | 14 |
| 11,909,498 | 6,436,684 | 6,569,511 | 135,972,332 | 1,556,826,346 | -938,608,829 | 754,189,849 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Southern California Edison Company | OS | | NA | NA | NA |
| 2 | Southern California Edison Company | SF | | NA | NA | NA |
| 3 | Southwestern Public Service Company | SF | | NA | NA | NA |
| 4 | Spanish Fork City | LF | | NA | NA | NA |
| 5 | Spanish Fork Wind Park 2, LLC | LU | | NA | NA | NA |
| 6 | Springville City | AD | | NA | NA | NA |
| 7 | Springville City | LF | | NA | NA | NA |
| 8 | State of CA Dept of Water Resources | SF | | NA | NA | NA |
| 9 | State of Utah | OS | | NA | NA | NA |
| 10 | Strawberry Electric Service District | LF | | NA | NA | NA |
| 11 | Sunnyside Cogeneration Associates | AD | | NA | NA | NA |
| 12 | Sunnyside Cogeneration Associates | LU | | 52.0 | 53.4 | 46.7 |
| 13 | Tacoma, City of | SF | | NA | NA | NA |
| 14 | Tesoro Refining and Marketing Company | OS | | NA | NA | NA |
| | Total | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 81,931 | | | | 2,229,889 | | 2,229,889 | 1 |
| 114,959 | | | | 6,669,868 | | 6,669,868 | 2 |
| 400 | | | | 22,000 | | 22,000 | 3 |
| 40 | | | | 3,647 | | 3,647 | 4 |
| 23,900 | | | | 1,220,102 | | 1,220,102 | 5 |
| 5 | | | | | 521 | 521 | 6 |
| 32 | | | | 4,129 | | 4,129 | 7 |
| 10,400 | | | | 1,057,128 | | 1,057,128 | 8 |
| | | | | | 1,219 | 1,219 | 9 |
| 64 | | | | 4,875 | | 4,875 | 10 |
| | | | | | -1,635,493 | -1,635,493 | 11 |
| 414,121 | | | 10,361,293 | 16,958,254 | | 27,319,547 | 12 |
| 29,384 | | | | 1,547,476 | 4,449 | 1,551,925 | 13 |
| 180,583 | | | | 8,768,019 | | 8,768,019 | 14 |
| 11,909,498 | 6,436,684 | 6,569,511 | 135,972,332 | 1,556,826,346 | -938,608,829 | 754,189,849 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

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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 | Thayn Hydro LLC | LU | | 0.3 | 0.4 | 0.3 |
| 2 | The Energy Authority | SF | | NA | NA | NA |
| 3 | TransAlta Energy Marketing Inc. | AD | | NA | NA | NA |
| 4 | TransAlta Energy Marketing Inc. | IF | | NA | NA | NA |
| 5 | TransAlta Energy Marketing Inc. | IF | | NA | NA | NA |
| 6 | TransAlta Energy Marketing Inc. | SF | | NA | NA | NA |
| 7 | Tri-State Generation & Transmission | AD | | NA | NA | NA |
| 8 | Tri-State Generation & Transmission | LF | | 35 | 34 | 29 |
| 9 | Tri-State Generation & Transmission | OS | | NA | NA | NA |
| 10 | Tri-State Generation & Transmission | SF | | NA | NA | NA |
| 11 | Tucson Electric Power | AD | | NA | NA | NA |
| 12 | Tucson Electric Power | OS | | NA | NA | NA |
| 13 | Tucson Electric Power | SF | | NA | NA | NA |
| 14 | Turlock Irrigation District | SF | | NA | NA | NA |
| | Total | | | | | |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 2,606 | | | 44,455 | 172,156 | | 216,611 | 1 |
| 57,929 | | | | 2,631,692 | | 2,631,692 | 2 |
| | | | | | -292,086 | -292,086 | 3 |
| 826,225 | | | | 47,531,084 | | 47,531,084 | 4 |
| | | | | | -420,320 | -420,320 | 5 |
| 181,908 | | | | 10,995,098 | | 10,995,098 | 6 |
| | | | | | 127,690 | 127,690 | 7 |
| 199,504 | | | 8,370,600 | 4,057,911 | | 12,428,511 | 8 |
| 205 | | | | 10,375 | | 10,375 | 9 |
| 51,551 | | | | 3,273,080 | 44,810 | 3,317,890 | 10 |
| 180 | | | | | 12,001 | 12,001 | 11 |
| 265 | | | | 16,125 | | 16,125 | 12 |
| 81,161 | | | | 5,302,723 | | 5,302,723 | 13 |
| 17,077 | | | | 1,026,262 | | 1,026,262 | 14 |
| 11,909,498 | 6,436,684 | 6,569,511 | 135,972,332 | 1,556,826,346 | -938,608,829 | 754,189,849 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | UBS Warburg Energy LLC | SF | | 25 | 25 | 25 |
| 2 | UNS Electric, Inc. | SF | | NA | NA | NA |
| 3 | UT Associated Municipal Power Systems | OS | | 77 | 77 | 77 |
| 4 | UT Associated Municipal Power Systems | SF | | NA | NA | NA |
| 5 | Utah Municipal Power Agency | OS | | NA | NA | NA |
| 6 | Wadeland South LLC | AD | | NA | NA | NA |
| 7 | Wadeland South LLC | LU | | 0.02 | 0.08 | 0.02 |
| 8 | Walla Walla, City of | LU | | 2.0 | 1.6 | 1.5 |
| 9 | Warm Springs Forest Products | AD | | NA | NA | NA |
| 10 | Warm Springs Forest Products | LU | | NA | NA | NA |
| 11 | Weber County, State of Utah | LU | | NA | NA | NA |
| 12 | Western Area Power Administration | AD | | NA | NA | NA |
| 13 | Western Area Power Administration | OS | | NA | NA | NA |
| 14 | Western Area Power Administration | SF | | NA | NA | NA |
| | Total | | | | | |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | COST/SETTLEMENT OF POWER Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | Line No. |
|---|---|---|---|---|---|---|---|
| 139,113 | | | 621,750 | 10,438,091 | 35,442 | 11,095,283 | 1 |
| 59 | | | | 2,350 | | 2,350 | 2 |
| 109,852 | | | 911,619 | 7,144,821 | 535,216 | 8,591,656 | 3 |
| 185 | | | | 19,225 | | 19,225 | 4 |
| 11,430 | | | | 576,512 | | 576,512 | 5 |
| | | | | | 3,771 | 3,771 | 6 |
| 146 | | | 1,868 | 4,734 | | 6,602 | 7 |
| 12,987 | | | 138,725 | 1,662,346 | | 1,801,071 | 8 |
| | | | | | 326 | 326 | 9 |
| 673 | | | | 15,984 | | 15,984 | 10 |
| 5,895 | | | | 222,087 | | 222,087 | 11 |
| | | | | | -301 | -301 | 12 |
| 1,400 | | | | 60,800 | | 60,800 | 13 |
| 11,673 | | | | 589,700 | 20,177 | 609,877 | 14 |
| 11,909,498 | 6,436,684 | 6,569,511 | 135,972,332 | 1,556,826,346 | -938,608,829 | 754,189,849 | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Weyerhaeuser Company | OS | | NA | NA | NA |
| 2 | Wolverine Creek Energy LLC | LU | | NA | NA | NA |
| 3 | Yakima Tieton | LU | | NA | NA | NA |
| 4 | Accrual true-up | NA | | NA | NA | NA |
| 5 | Line Loss Return | AD | | NA | NA | NA |
| 6 | Bookout Purchases | AD | | NA | NA | NA |
| 7 | Potential Liability | AD | | NA | NA | NA |
| 8 | Trade Purchases | AD | | NA | NA | NA |
| 9 | | | | | | |
| 10 | | | | | | |
| 11 | | | | | | |
| 12 | Power Exchanges | | | | | |
| 13 | Arizona Public Service Co. | EX | 306 | NA | NA | NA |
| 14 | Avista Corp. | EX | 554 | NA | NA | NA |
| | Total | | | | | |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 210,680 | | | | 13,999,397 | | 13,999,397 | 1 |
| 170,268 | | | | 9,206,402 | | 9,206,402 | 2 |
| 6,764 | | | | 339,543 | | 339,543 | 3 |
| | | | | | -6,203,863 | -6,203,863 | 4 |
| | | | | | -4,585,952 | -4,585,952 | 5 |
| -17,464,081 | | | | | -886,623,896 | -886,623,896 | 6 |
| | | | | | -1,932,675 | -1,932,675 | 7 |
| | | | | | -127,855,541 | -127,855,541 | 8 |
| | | | | | | | 9 |
| | | | | | | | 10 |
| | | | | | | | 11 |
| | | | | | | | 12 |
| | 569,553 | 569,267 | | | -2,974,143 | -2,974,143 | 13 |
| | 1,770 | | | | | | 14 |
| 11,909,498 | 6,436,684 | 6,569,511 | 135,972,332 | 1,556,826,346 | -938,608,829 | 754,189,849 | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations)<br>(a) | Statistical Classification<br>(b) | FERC Rate Schedule or Tariff Number<br>(c) | Average Monthly Billing Demand (MW)<br>(d) | Actual Demand (MW) | |
|---|---|---|---|---|---|---|
| | | | | | Average Monthly NCP Demand<br>(e) | Average Monthly CP Demand<br>(f) |
| 1 | Basin Electric Power Cooperative | EX | T-11 | NA | NA | NA |
| 2 | Black Hills Power, Inc. | EX | 246 | NA | NA | NA |
| 3 | Bonneville Power Administration | AD | 237 | NA | NA | NA |
| 4 | Bonneville Power Administration | EX | 237 | NA | NA | NA |
| 5 | Bonneville Power Administration | EX | 256 | NA | NA | NA |
| 6 | Bonneville Power Administration | EX | 347 | NA | NA | NA |
| 7 | Bonneville Power Administration | EX | 368 | NA | NA | NA |
| 8 | Bonneville Power Administration | EX | 554 | NA | NA | NA |
| 9 | Bonneville Power Administration | EX | (16) | NA | NA | NA |
| 10 | Bonneville Power Administration | EX | T-11 | NA | NA | NA |
| 11 | Bonneville Power Administration | EX | T-12 | NA | NA | NA |
| 12 | Chelan County Pub Utility Dist No. 1 | EX | 554 | NA | NA | NA |
| 13 | Chelan County Pub Utility Dist No. 1 | EX | T-12 | NA | NA | NA |
| 14 | Colockum Transmission Company | EX | T-12 | NA | NA | NA |
| | Total | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| | 10,183 | 10,084 | | | 71,613 | 71,613 | 1 |
| | 91 | | | | | | 2 |
| | | | | | -77,970 | -77,970 | 3 |
| | | 61,488 | | | -9,430 | -9,430 | 4 |
| | 53 | 53 | | | -424 | -424 | 5 |
| | 1,634,817 | 1,625,287 | | | 615,000 | 615,000 | 6 |
| | 222,273 | 222,273 | | | | | 7 |
| | 238,349 | 77,113 | | | | | 8 |
| | 1,856,594 | 1,856,594 | | | -4,878,060 | -4,878,060 | 9 |
| | 9,063 | 6,567 | | | 132,449 | 132,449 | 10 |
| | 109,074 | 104,735 | | | 551,727 | 551,727 | 11 |
| | | 16,492 | | | | | 12 |
| | | 83,712 | | | | | 13 |
| | | 267,942 | | | | | 14 |
| 11,909,498 | 6,436,684 | 6,569,511 | 135,972,332 | 1,556,826,346 | -938,608,829 | 754,189,849 | |

## 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 | Constellation Energy Commodities Group | EX | T-11 | NA | NA | NA |
| 2 | Cowlitz County Pub Utility Dist No. 1 | EX | 554 | NA | NA | NA |
| 3 | Deseret Power Electric Cooperative | AD | 280 | NA | NA | NA |
| 4 | Deseret Power Electric Cooperative | EX | 280 | NA | NA | NA |
| 5 | Emerald Peoples Utility District | EX | 351 | NA | NA | NA |
| 6 | Eugene Water & Electric Board | EX | T-11 | NA | NA | NA |
| 7 | Eugene Water & Electric Board | EX | T-12 | NA | NA | NA |
| 8 | Flathead Electric Cooperative | EX | T-11 | NA | NA | NA |
| 9 | Grant County Pub Utility Dist No. 2 | EX | 554 | NA | NA | NA |
| 10 | Iberdrola Renewables, Inc. | EX | T-11 | NA | NA | NA |
| 11 | Idaho Power Company | EX | 380 | NA | NA | NA |
| 12 | Portland General Electric Co. | EX | 554 | NA | NA | NA |
| 13 | Powerex | EX | T-11 | NA | NA | NA |
| 14 | Public Service Company of Colorado | EX | 319 | NA | NA | NA |
| | Total | | | | | |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| | 6,301 | 2,129 | | | 150,345 | 150,345 | 1 |
| | 185,517 | 220,349 | | | | | 2 |
| | 168 | -540 | | | 354,823 | 354,823 | 3 |
| | 59,059 | 56,239 | | | -55,691 | -55,691 | 4 |
| | | 512 | | | -12,791 | -12,791 | 5 |
| | 167 | 260 | | | -7,926 | -7,926 | 6 |
| | 20,354 | 20,215 | | | 6,950 | 6,950 | 7 |
| | 9,094 | 176 | | | 530,958 | 530,958 | 8 |
| | 12,267 | 44,241 | | | | | 9 |
| | 16,247 | 8,934 | | | 364,190 | 364,190 | 10 |
| | 288,340 | 279,694 | | | | | 11 |
| | 155,718 | 154,551 | | | | | 12 |
| | 1,241 | 803 | | | 30,008 | 30,008 | 13 |
| | 5,655 | | | | | | 14 |
| 11,909,498 | 6,436,684 | 6,569,511 | 135,972,332 | 1,556,826,346 | -938,608,829 | 754,189,849 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Public Service Company of Colorado | EX | 320 | NA | NA | NA |
| 2 | Public Service Company of Colorado | EX | T-12 | NA | NA | NA |
| 3 | Redding, City of | EX | 364 | NA | NA | NA |
| 4 | SUEZ Energy Marketing NA, Inc. | EX | T-12 | NA | NA | NA |
| 5 | Seattle City Light | EX | 554 | NA | NA | NA |
| 6 | Sempra Energy Solutions | EX | T-11 | NA | NA | NA |
| 7 | Tri-State Generation & Transmission | AD | 319 | NA | NA | NA |
| 8 | Tri-State Generation & Transmission | EX | 319 | NA | NA | NA |
| 9 | UT Associated Municipal Power Systems | AD | T-11 | NA | NA | NA |
| 10 | UT Associated Municipal Power Systems | EX | T-11 | NA | NA | NA |
| 11 | Utah Municipal Power Agency | EX | T-11 | NA | NA | NA |
| 12 | Warm Springs Power Enterprises | EX | T-11 | NA | NA | NA |
| 13 | Western Area Power Administration | AD | LAS-4 | NA | NA | NA |
| 14 | Western Area Power Administration | EX | 262 | NA | NA | NA |
| | Total | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| | 219,575 | 218,853 | | | 900,000 | 900,000 | 1 |
| | 85,087 | 83,841 | | | -15,581 | -15,581 | 2 |
| | 114,387 | 119,919 | | | -308,616 | -308,616 | 3 |
| | | | | | 293,003 | 293,003 | 4 |
| | 355,599 | 372,059 | | | -987,827 | -987,827 | 5 |
| | 6,590 | 2,672 | | | 170,067 | 170,067 | 6 |
| | | | | | 258 | 258 | 7 |
| | 5,645 | | | | 26,084 | 26,084 | 8 |
| | -4 | 2 | | | -342 | -342 | 9 |
| | 127,200 | 58,621 | | | 3,637,424 | 3,637,424 | 10 |
| | 53,790 | 4,423 | | | 3,137,246 | 3,137,246 | 11 |
| | 2,704 | 5,384 | | | -157,180 | -157,180 | 12 |
| | 2,742 | -3,407 | | | 59,474 | 59,474 | 13 |
| | 3,288 | | | | | | 14 |
| 11,909,498 | 6,436,684 | 6,569,511 | 135,972,332 | 1,556,826,346 | -938,608,829 | 754,189,849 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Western Area Power Administration | EX | LAS-4 | NA | NA | NA |
| 2 | | | | | | |
| 3 | System Deviation | NA | | NA | NA | NA |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | | | | | |
| 8 | | | | | | |
| 9 | | | | | | |
| 10 | | | | | | |
| 11 | | | | | | |
| 12 | | | | | | |
| 13 | | | | | | |
| 14 | | | | | | |
| | Total | | | | | |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| | 48,133 | 17,974 | | | 71,162 | 71,162 | 1 |
| | | | | | | | 2 |
| -13,122 | | | | | | | 3 |
| | | | | | | | 4 |
| | | | | | | | 5 |
| | | | | | | | 6 |
| | | | | | | | 7 |
| | | | | | | | 8 |
| | | | | | | | 9 |
| | | | | | | | 10 |
| | | | | | | | 11 |
| | | | | | | | 12 |
| | | | | | | | 13 |
| | | | | | | | 14 |
| 11,909,498 | 6,436,684 | 6,569,511 | 135,972,332 | 1,556,826,346 | -938,608,829 | 754,189,849 | |

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

Settlement adjustment.

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

Damages for non-delivery of generation.

**Schedule Page: 326 Line No.: 5 Column: b**

Settlement adjustment.

**Schedule Page: 326 Line No.: 5 Column: l**

Settlement adjustment.

**Schedule Page: 326 Line No.: 6 Column: b**

Arizona Public Service - Contract Termination Date: October 31, 2020.

**Schedule Page: 326 Line No.: 7 Column: b**

Secondary, economy and/or non-firm.

**Schedule Page: 326 Line No.: 9 Column: b**

Secondary, economy and/or non-firm.

**Schedule Page: 326 Line No.: 9 Column: l**

Operating reserves.

**Schedule Page: 326 Line No.: 10 Column: l**

Reserve Share.

**Schedule Page: 326 Line No.: 11 Column: l**

Financial Swap.

**Schedule Page: 326 Line No.: 13 Column: l**

Financial Swap.

**Schedule Page: 326 Line No.: 14 Column: b**

Settlement adjustment.

**Schedule Page: 326 Line No.: 14 Column: l**

Settlement adjustment.

**Schedule Page: 326.1 Line No.: 1 Column: l**

Financial Swap.

**Schedule Page: 326.1 Line No.: 2 Column: l**

Financial Swap.

**Schedule Page: 326.1 Line No.: 3 Column: b**

Under Electric Service Agreement subject to termination upon timely notification.

**Schedule Page: 326.1 Line No.: 6 Column: l**

Non-generation agreement.

**Schedule Page: 326.1 Line No.: 8 Column: b**

Settlement adjustment.

**Schedule Page: 326.1 Line No.: 8 Column: l**

Operation and maintenance expense associated wtih the combustion turbine located in Rapid City, South Dakota.

**Schedule Page: 326.1 Line No.: 9 Column: l**

Operation and maintenance expense associated wtih the combustion turbine located in Rapid City, South Dakota.

**Schedule Page: 326.1 Line No.: 10 Column: b**

Secondary, economy and/or non-firm.

**Schedule Page: 326.1 Line No.: 12 Column: b**

Secondary, economy and/or non-firm.

**Schedule Page: 326.1 Line No.: 14 Column: b**

Blanding City - Contract Termination Date: March 31, 2012.

**Schedule Page: 326.2 Line No.: 2 Column: b**

Settlement adjustment.

**Schedule Page: 326.2 Line No.: 2 Column: l**

Operating reserves.

**Schedule Page: 326.2 Line No.: 3 Column: b**

| Name of Respondent | This Report is: | Date of Report | Year/Period of Report |
| --- | --- | --- | --- |
| PacifiCorp | (1) X An Original<br>(2) _ A Resubmission | (Mo, Da, Yr)<br>03/31/2009 | 2008/Q4 |

FOOTNOTE DATA

Bonneville Power Administration - Contract Termination Date: August 31, 2011.

***Schedule Page: 326.2 Line No.: 4 Column: b***

Bonneville Power Adminstration - Contract Termination Date: 30 days written notice.

***Schedule Page: 326.2 Line No.: 4 Column: l***

Operating reserves.

***Schedule Page: 326.2 Line No.: 5 Column: b***

Secondary, economy and/or non-firm.

***Schedule Page: 326.2 Line No.: 5 Column: l***

Operating reserves.

***Schedule Page: 326.2 Line No.: 6 Column: l***

Reserve Share.

***Schedule Page: 326.2 Line No.: 9 Column: b***

Settlement adjustment.

***Schedule Page: 326.2 Line No.: 9 Column: l***

Settlement adjustment.

***Schedule Page: 326.2 Line No.: 11 Column: b***

Settlement adjustment.

***Schedule Page: 326.2 Line No.: 11 Column: l***

Settlement adjustment.

***Schedule Page: 326.2 Line No.: 12 Column: b***

Secondary, economy and/or non-firm.

***Schedule Page: 326.2 Line No.: 14 Column: b***

Settlement adjustment.

***Schedule Page: 326.2 Line No.: 14 Column: l***

Settlement adjustment.

***Schedule Page: 326.3 Line No.: 2 Column: l***

Operating expense, bond interest, amortization and taxes.

***Schedule Page: 326.3 Line No.: 3 Column: b***

Secondary, economy and/or non-firm.

***Schedule Page: 326.3 Line No.: 3 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.: 4 Column: l***

Reserve Share.

***Schedule Page: 326.3 Line No.: 5 Column: b***

Settlement adjustment.

***Schedule Page: 326.3 Line No.: 5 Column: l***

Settlement adjustment.

***Schedule Page: 326.3 Line No.: 6 Column: l***

Financial Swap.

***Schedule Page: 326.3 Line No.: 9 Column: b***

Settlement adjustment.

***Schedule Page: 326.3 Line No.: 9 Column: l***

Settlement adjustment.

***Schedule Page: 326.3 Line No.: 11 Column: b***

Secondary, economy and/or non-firm.

***Schedule Page: 326.3 Line No.: 13 Column: b***

Settlement adjustment.

***Schedule Page: 326.3 Line No.: 13 Column: l***

Settlement adjustment.

***Schedule Page: 326.3 Line No.: 14 Column: b***

Secondary, economy and/or non-firm.

***Schedule Page: 326.4 Line No.: 1 Column: l***

Financial Swap.

***Schedule Page: 326.4 Line No.: 2 Column: b***

Secondary, economy and/or non-firm.

***Schedule Page: 326.4 Line No.: 2 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.: 3 Column: b***

Settlement adjustment.

***Schedule Page: 326.4 Line No.: 3 Column: l***

Settlement adjustment.

***Schedule Page: 326.4 Line No.: 4 Column: l***

Financial Swap.

***Schedule Page: 326.4 Line No.: 6 Column: b***

Settlement adjustment.

***Schedule Page: 326.4 Line No.: 6 Column: l***

Settlement adjustment.

***Schedule Page: 326.4 Line No.: 11 Column: b***

Deseret Generation & Transmission - Contract Termination Date: September 30, 2024.

***Schedule Page: 326.4 Line No.: 11 Column: l***

Operation and maintenance expense associated with a coal-fired generating facility located in Vernal, Utah.

***Schedule Page: 326.4 Line No.: 12 Column: l***

Damages for non-delivery of generation.

***Schedule Page: 326.4 Line No.: 13 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.: 2 Column: b***

Settlement adjustment.

***Schedule Page: 326.5 Line No.: 2 Column: l***

Operating expense, bond interest, amortization and taxes.

***Schedule Page: 326.5 Line No.: 3 Column: l***

Operating expense, bond interest, amortization and taxes.

***Schedule Page: 326.5 Line No.: 4 Column: b***

Secondary, economy and/or non-firm.

***Schedule Page: 326.5 Line No.: 4 Column: l***

Operating expense, bond interest, amortization and taxes.

***Schedule Page: 326.5 Line No.: 5 Column: l***

Reserve Share.

***Schedule Page: 326.5 Line No.: 7 Column: b***

Settlement adjustment.

***Schedule Page: 326.5 Line No.: 7 Column: l***

Settlement adjustment.

***Schedule Page: 326.5 Line No.: 9 Column: b***

Settlement adjustment.

***Schedule Page: 326.5 Line No.: 9 Column: l***

Settlement adjustment.

***Schedule Page: 326.5 Line No.: 13 Column: l***

Line Loss.

***Schedule Page: 326.6 Line No.: 2 Column: b***

Settlement adjustment.

***Schedule Page: 326.6 Line No.: 2 Column: l***

Settlement adjustment.

**Schedule Page: 326.6 Line No.: 9 Column: b**

Under Electric Service Agreement subject to termination upon timely notification.

**Schedule Page: 326.6 Line No.: 10 Column: b**

Settlement adjustment.

**Schedule Page: 326.6 Line No.: 12 Column: b**

Settlement adjustment.

**Schedule Page: 326.6 Line No.: 12 Column: l**

Settlement adjustment.

**Schedule Page: 326.6 Line No.: 13 Column: l**

Financial Swap.

**Schedule Page: 326.7 Line No.: 1 Column: b**

Secondary, economy and/or non-firm.

**Schedule Page: 326.7 Line No.: 1 Column: l**

Load curtailment.

**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.: 9 Column: b**

Under Electric Service Agreement subject to termination upon timely notification.

**Schedule Page: 326.7 Line No.: 10 Column: b**

Settlement adjustment.

**Schedule Page: 326.7 Line No.: 10 Column: l**

Operating expense, bond interest, amortization and taxes.

**Schedule Page: 326.7 Line No.: 11 Column: b**

Grant County Public Utility District No. 2 - Contract Termination Date: 2 years written notice.

**Schedule Page: 326.7 Line No.: 11 Column: l**

Ancillary services and cost recovery adjustment.

**Schedule Page: 326.7 Line No.: 12 Column: l**

Operating expense, bond interest, amortization and taxes.

**Schedule Page: 326.7 Line No.: 13 Column: l**

Operating expense, bond interest, amortization and taxes.

**Schedule Page: 326.7 Line No.: 14 Column: b**

Secondary, economy and/or non-firm.

**Schedule Page: 326.7 Line No.: 14 Column: l**

Operating reserves.

**Schedule Page: 326.8 Line No.: 1 Column: l**

Reserve Share.

**Schedule Page: 326.8 Line No.: 3 Column: b**

Under Electric Service Agreement subject to termination upon timely notification.

**Schedule Page: 326.8 Line No.: 4 Column: a**

Hermiston Generating Company, L.P. operates the Hermiston Generating Plant, which is jointly owned. PacifiCorp owns 50% of the plant. See page 402.3 column (c) of this Form No. 1 for further information on the Hermiston Generating Plant.

**Schedule Page: 326.8 Line No.: 4 Column: b**

Settlement adjustment.

**Schedule Page: 326.8 Line No.: 4 Column: l**

On peak incentive, supplemental dispatch efficiency expense, start-up charges and committee settlements and Settlement adjustment.

**Schedule Page: 326.8 Line No.: 5 Column: a**

Hermiston Generating Company, L.P. operates the Hermiston Generating Plant, which is jointly owned. PacifiCorp owns 50% of the plant. See page 402.3 column (c) of this Form No. 1 for further information on the Hermiston Generating Plant.

**Schedule Page: 326.8 Line No.: 5 Column: l**

| Name of Respondent<br>PacifiCorp | This Report is:<br>(1) X An Original<br>(2) _ A Resubmission | Date of Report (Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>2008/Q4 |
|---|---|---|---|

FOOTNOTE DATA

On peak incentive, supplemental dispatch efficiency expense, start-up charges and committee settlements.

***Schedule Page: 326.8 Line No.: 8 Column: b***

Hurricane, City of - Contract Termination Date: August 31, 2012.

***Schedule Page: 326.8 Line No.: 9 Column: b***

Secondary, economy and/or non-firm.

***Schedule Page: 326.8 Line No.: 10 Column: l***

Financial Swap.

***Schedule Page: 326.8 Line No.: 11 Column: b***

Settlement adjustment.

***Schedule Page: 326.8 Line No.: 11 Column: l***

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

***Schedule Page: 326.8 Line No.: 12 Column: l***

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

***Schedule Page: 326.8 Line No.: 13 Column: l***

Line loss.

***Schedule Page: 326.8 Line No.: 14 Column: l***

Reserve Share.

***Schedule Page: 326.9 Line No.: 3 Column: b***

Secondary, economy and/or non-firm.

***Schedule Page: 326.9 Line No.: 4 Column: b***

Settlement adjustment.

***Schedule Page: 326.9 Line No.: 4 Column: l***

Settlement adjustment.

***Schedule Page: 326.9 Line No.: 5 Column: l***

Financial Swap.

***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.: 10 Column: l***

Fixed annual payment.

***Schedule Page: 326.9 Line No.: 12 Column: l***

Financial Swap.

***Schedule Page: 326.9 Line No.: 13 Column: b***

Secondary, economy and/or non-firm.

***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.: 6 Column: b***

Magnesium Corporation of America - Contract Termination Date: December 31, 2009.

***Schedule Page: 326.10 Line No.: 6 Column: l***

Operating reserves.

***Schedule Page: 326.10 Line No.: 7 Column: b***

Settlement adjustment.

***Schedule Page: 326.10 Line No.: 7 Column: l***

Settlement adjustment.

***Schedule Page: 326.10 Line No.: 9 Column: l***

Financial Swap.

***Schedule Page: 326.10 Line No.: 10 Column: b***

Settlement adjustment.

**Schedule Page: 326.10 Line No.: 10 Column: l**

Settlement adjustment.

**Schedule Page: 326.10 Line No.: 14 Column: l**

Compensation for interruptible service and operating reserves.

**Schedule Page: 326.11 Line No.: 1 Column: b**

Under Electric Service Agreement subject to termination upon timely notification.

**Schedule Page: 326.11 Line No.: 2 Column: b**

Settlement adjustment.

**Schedule Page: 326.11 Line No.: 2 Column: l**

Settlement adjustment.

**Schedule Page: 326.11 Line No.: 4 Column: l**

Financial Swap.

**Schedule Page: 326.11 Line No.: 9 Column: b**

Under Electric Service Agreement subject to termination upon timely notification.

**Schedule Page: 326.11 Line No.: 10 Column: l**

Line loss.

**Schedule Page: 326.11 Line No.: 13 Column: l**

Reserve Share.

**Schedule Page: 326.12 Line No.: 2 Column: l**

Operating reserves.

**Schedule Page: 326.12 Line No.: 7 Column: b**

Secondary, economy and/or non-firm.

**Schedule Page: 326.12 Line No.: 12 Column: b**

Secondary, economy and/or non-firm.

**Schedule Page: 326.12 Line No.: 14 Column: b**

Under Electric Service Agreement subject to termination upon timely notification.

**Schedule Page: 326.13 Line No.: 2 Column: b**

Settlement adjustment.

**Schedule Page: 326.13 Line No.: 2 Column: l**

Line loss.

**Schedule Page: 326.13 Line No.: 3 Column: l**

Line loss.

**Schedule Page: 326.13 Line No.: 4 Column: b**

Settlement adjustment.

**Schedule Page: 326.13 Line No.: 4 Column: l**

Operation expense plus amortization of unrecovered costs of Cove Project.

**Schedule Page: 326.13 Line No.: 5 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.: 5 Column: l**

Operation expense plus amortization of unrecovered costs of Cove Project.

**Schedule Page: 326.13 Line No.: 6 Column: b**

Secondary, economy and/or non-firm.

**Schedule Page: 326.13 Line No.: 6 Column: l**

Operating reserves.

**Schedule Page: 326.13 Line No.: 7 Column: l**

Reserve Share.

**Schedule Page: 326.13 Line No.: 8 Column: b**

Settlement adjustment.

**Schedule Page: 326.13 Line No.: 8 Column: l**

Settlement adjustment.

| Name of Respondent<br>PacifiCorp | This Report is:<br>(1) X An Original<br>(2) _ A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>2008/Q4 |
|---|---|---|---|

FOOTNOTE DATA

***Schedule Page: 326.13 Line No.: 10 Column: b***

Secondary, economy and/or non-firm.

***Schedule Page: 326.13 Line No.: 10 Column: l***

Load curtailment.

***Schedule Page: 326.13 Line No.: 12 Column: b***

Under Electric Service Agreement subject to termination upon timely notification.

***Schedule Page: 326.13 Line No.: 13 Column: b***

Settlement adjustment.

***Schedule Page: 326.13 Line No.: 13 Column: l***

Settlement adjustment.

***Schedule Page: 326.14 Line No.: 1 Column: b***

Settlement adjustment.

***Schedule Page: 326.14 Line No.: 1 Column: l***

Settlement adjustment.

***Schedule Page: 326.14 Line No.: 2 Column: b***

Secondary, economy and/or non-firm.

***Schedule Page: 326.14 Line No.: 3 Column: l***

Line Loss.

***Schedule Page: 326.14 Line No.: 4 Column: b***

Public Utility District No. 1 of Lewis County - Contract Termination Date: 60 days written notice.

***Schedule Page: 326.14 Line No.: 5 Column: l***

Green Tags.

***Schedule Page: 326.14 Line No.: 6 Column: l***

Reserve Share.

***Schedule Page: 326.14 Line No.: 7 Column: b***

Settlement adjustment.

***Schedule Page: 326.14 Line No.: 7 Column: l***

Settlement adjustment.

***Schedule Page: 326.14 Line No.: 12 Column: b***

Secondary, economy and/or non-firm.

***Schedule Page: 326.14 Line No.: 14 Column: b***

Secondary, economy and/or non-firm.

***Schedule Page: 326.15 Line No.: 2 Column: l***

Availability requirement shortfall.

***Schedule Page: 326.15 Line No.: 5 Column: l***

Start-up and variable operation and maintenance charges.

***Schedule Page: 326.15 Line No.: 6 Column: b***

Settlement adjustment.

***Schedule Page: 326.15 Line No.: 6 Column: l***

Settlement adjustment.

***Schedule Page: 326.15 Line No.: 7 Column: b***

Sacramento Municipal Utility District - Contract Termination Date: December 31, 2014.

***Schedule Page: 326.15 Line No.: 9 Column: b***

Secondary, economy and/or non-firm.

***Schedule Page: 326.15 Line No.: 10 Column: l***

Line loss.

***Schedule Page: 326.15 Line No.: 11 Column: b***

Settlement adjustment.

***Schedule Page: 326.15 Line No.: 11 Column: l***

Settlement adjustment.

***Schedule Page: 326.16 Line No.: 1 Column: l***

Damages for non-delivery of generation.

| Name of Respondent<br>PacifiCorp | This Report is:<br>(1) X An Original<br>(2) _ A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>2008/Q4 |
|---|---|---|---|

FOOTNOTE DATA

**Schedule Page: 326.16 Line No.: 2 Column: l**

Reserve Share.

**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**

Financial Swap.

**Schedule Page: 326.16 Line No.: 7 Column: b**

Settlement adjustment.

**Schedule Page: 326.16 Line No.: 7 Column: l**

Settlement adjustment.

**Schedule Page: 326.16 Line No.: 8 Column: b**

Secondary, economy and/or non-firm.

**Schedule Page: 326.16 Line No.: 9 Column: l**

Financial Swap.

**Schedule Page: 326.16 Line No.: 10 Column: l**

Reserve Share and Line loss.

**Schedule Page: 326.16 Line No.: 12 Column: b**

Secondary, economy and/or non-firm.

**Schedule Page: 326.16 Line No.: 12 Column: l**

Load curtailment.

**Schedule Page: 326.17 Line No.: 1 Column: b**

Secondary, economy and/or non-firm.

**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: b**

Settlement adjustment.

**Schedule Page: 326.17 Line No.: 6 Column: l**

Settlement adjustment.

**Schedule Page: 326.17 Line No.: 7 Column: b**

Under Electric Service Agreement subject to termination upon timely notification.

**Schedule Page: 326.17 Line No.: 9 Column: b**

Secondary, economy and/or non-firm.

**Schedule Page: 326.17 Line No.: 9 Column: l**

Load curtailment.

**Schedule Page: 326.17 Line No.: 10 Column: b**

Under Electric Service Agreement subject to termination upon timely notification.

**Schedule Page: 326.17 Line No.: 11 Column: b**

Settlement adjustment.

**Schedule Page: 326.17 Line No.: 11 Column: l**

Settlement adjustment.

**Schedule Page: 326.17 Line No.: 13 Column: l**

Reserve Share.

**Schedule Page: 326.17 Line No.: 14 Column: b**

Secondary, economy and/or non-firm.

**Schedule Page: 326.18 Line No.: 3 Column: b**

Settlement adjustment.

**Schedule Page: 326.18 Line No.: 3 Column: l**

Operating reserve reimbursement.

**Schedule Page: 326.18 Line No.: 5 Column: l**

Operating reserve reimbursement.

***Schedule Page: 326.18 Line No.: 7 Column: b***

Settlement adjustment.

***Schedule Page: 326.18 Line No.: 7 Column: l***

Settlement on balance of energy remaining in account.

***Schedule Page: 326.18 Line No.: 8 Column: b***

Tri-State Generation & Transmission - Contract Termination Date: December 31, 2020.

***Schedule Page: 326.18 Line No.: 9 Column: b***

Secondary, economy and/or non-firm.

***Schedule Page: 326.18 Line No.: 10 Column: l***

Line loss.

***Schedule Page: 326.18 Line No.: 11 Column: b***

Settlement adjustment.

***Schedule Page: 326.18 Line No.: 11 Column: l***

Settlement adjustment.

***Schedule Page: 326.18 Line No.: 12 Column: b***

Secondary, economy and/or non-firm.

***Schedule Page: 326.19 Line No.: 1 Column: l***

Financial Swap.

***Schedule Page: 326.19 Line No.: 3 Column: b***

Secondary, economy and/or non-firm.

***Schedule Page: 326.19 Line No.: 3 Column: l***

Start-up and variable operation and maintenance charges.

***Schedule Page: 326.19 Line No.: 5 Column: b***

Secondary, economy and/or non-firm.

***Schedule Page: 326.19 Line No.: 6 Column: b***

Settlement adjustment.

***Schedule Page: 326.19 Line No.: 6 Column: l***

Settlement adjustment.

***Schedule Page: 326.19 Line No.: 9 Column: b***

Settlement adjustment.

***Schedule Page: 326.19 Line No.: 9 Column: l***

Settlement adjustment.

***Schedule Page: 326.19 Line No.: 12 Column: b***

Settlement adjustment.

***Schedule Page: 326.19 Line No.: 12 Column: l***

Line loss.

***Schedule Page: 326.19 Line No.: 13 Column: b***

Secondary, economy and/or non-firm.

***Schedule Page: 326.19 Line No.: 14 Column: l***

Line loss.

***Schedule Page: 326.20 Line No.: 1 Column: b***

Secondary, economy and/or non-firm.

***Schedule Page: 326.20 Line No.: 4 Column: l***

Represents the difference between actual purchase expenses for the period as reflected on the individual line items with this schedule, and the accruals charged to account 555 during this period and excess net power cost deferrals.

***Schedule Page: 326.20 Line No.: 5 Column: l***

Delivery of energy to settle loss dispute.

***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.: 13 Column: l***

Exchange energy expense.

***Schedule Page: 326.21 Line No.: 1 Column: l***

Imbalance energy.

***Schedule Page: 326.21 Line No.: 3 Column: b***

Settlement adjustment.

***Schedule Page: 326.21 Line No.: 3 Column: l***

Exchange energy expense.

***Schedule Page: 326.21 Line No.: 4 Column: l***

Exchange energy expense.

***Schedule Page: 326.21 Line No.: 5 Column: l***

Load factoring and storage charges.

***Schedule Page: 326.21 Line No.: 6 Column: l***

Exchange energy expense.

***Schedule Page: 326.21 Line No.: 9 Column: h***

These megawatthours represent book entry only. No actual energy transfer took place.

***Schedule Page: 326.21 Line No.: 9 Column: i***

These megawatthours represent book entry only. No actual energy transfer took place.

***Schedule Page: 326.21 Line No.: 9 Column: l***

Pacific Northwest Electric Power Planning and Conservation Act, FERC Electric Tariff, Original Volume No. 1.

***Schedule Page: 326.21 Line No.: 10 Column: l***

Imbalance energy.

***Schedule Page: 326.21 Line No.: 11 Column: l***

Exchange energy expense and Imbalance energy.

***Schedule Page: 326.22 Line No.: 1 Column: l***

Imbalance energy.

***Schedule Page: 326.22 Line No.: 3 Column: b***

Settlement adjustment.

***Schedule Page: 326.22 Line No.: 3 Column: l***

Imbalance energy.

***Schedule Page: 326.22 Line No.: 4 Column: l***

Imbalance energy.

***Schedule Page: 326.22 Line No.: 5 Column: l***

Load factoring and storage charges.

***Schedule Page: 326.22 Line No.: 6 Column: l***

Imbalance energy.

***Schedule Page: 326.22 Line No.: 7 Column: l***

Exchange energy expense.

***Schedule Page: 326.22 Line No.: 8 Column: l***

Imbalance energy.

***Schedule Page: 326.22 Line No.: 10 Column: l***

Imbalance energy.

***Schedule Page: 326.22 Line No.: 13 Column: l***

Imbalance energy.

***Schedule Page: 326.23 Line No.: 1 Column: l***

Load factoring and storage charges.

***Schedule Page: 326.23 Line No.: 2 Column: l***

Exchange energy expense.

***Schedule Page: 326.23 Line No.: 3 Column: l***

Exchange energy expense.

***Schedule Page: 326.23 Line No.: 4 Column: l***

Imbalance energy.

***Schedule Page: 326.23 Line No.: 5 Column: l***

Exchange energy expense.

***Schedule Page: 326.23 Line No.: 6 Column: l***

Imbalance energy.

***Schedule Page: 326.23 Line No.: 7 Column: b***

Settlement adjustment.

***Schedule Page: 326.23 Line No.: 7 Column: l***

Imbalance energy.

***Schedule Page: 326.23 Line No.: 8 Column: l***

Imbalance energy.

***Schedule Page: 326.23 Line No.: 9 Column: b***

Settlement adjustment.

***Schedule Page: 326.23 Line No.: 9 Column: l***

Imbalance energy.

***Schedule Page: 326.23 Line No.: 10 Column: l***

Imbalance energy.

***Schedule Page: 326.23 Line No.: 11 Column: l***

Imbalance energy.

***Schedule Page: 326.23 Line No.: 12 Column: l***

Imbalance energy.

***Schedule Page: 326.23 Line No.: 13 Column: b***

Settlement adjustment.

***Schedule Page: 326.23 Line No.: 13 Column: l***

Imbalance energy.

***Schedule Page: 326.24 Line No.: 1 Column: l***

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)

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

| Line No. | Payment By (Company of Public Authority) (Footnote Affiliation) (a) | Energy Received From (Company of Public Authority) (Footnote Affiliation) (b) | Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c) | Statistical Classification (d) |
|---|---|---|---|---|
| 1 | Basin Electric Power Cooperative | Western Area Power Administration | Powder River Energy Corp. | FNO |
| 2 | Basin Electric Power Cooperative | Western Area Power Administration | Powder River Energy Corp. | AD |
| 3 | Basin Electric Power Cooperative | Western Area Power Administration | Powder River Energy Corp. | FNO |
| 4 | Basin Electric Power Cooperative | Western Area Power Administration | Powder River Energy Corp. | AD |
| 5 | Basin Electric Power Cooperative | | | NF |
| 6 | Bear Energy, LP | | | NF |
| 7 | Black Hills Power & Light Company | | | NF |
| 8 | Black Hills Power & Light Company | | | AD |
| 9 | Black Hills Power & Light Company | PacifiCorp Merchant | Montana-Dakota Utilities | FNO |
| 10 | Black Hills Power & Light Company | PacifiCorp Merchant | Montana-Dakota Utilities | AD |
| 11 | Black Hills Power & Light Company | PacifiCorp Merchant | Black Hills Power & Light Company | LFP |
| 12 | Black Hills Power & Light Company | PacifiCorp Merchant | Black Hills Power & Light Company | AD |
| 13 | Bonneville Power Administration | Bonneville Power Administration | Bonneville Power Administration | OS |
| 14 | Bonneville Power Administration | Bonneville Power Administration | Bonneville Power Administration | 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 | Umpqua Indian Utility Cooperative | FNO |
| 18 | Bonneville Power Administration | Bonneville Power Administration | Umpqua Indian Utility Cooperative | AD |
| 19 | Bonneville Power Administration | U. S. Bureau of Reclamation | Bonneville Power Administration | LFP |
| 20 | Bonneville Power Administration | U. S. Bureau of Reclamation | Bonneville Power Administration | AD |
| 21 | Bonneville Power Administration | Bonneville Power Administration | Bonneville Power Administration | OS |
| 22 | Bonneville Power Administration | Bonneville Power Administration | Bonneville Power Administration | AD |
| 23 | Bonneville Power Administration | Bonneville Power Administration | Yakama Power | FNO |
| 24 | Bonneville Power Administration | Bonneville Power Administration | Yakama Power | AD |
| 25 | Bonneville Power Administration | Bonneville Power Administration | Bonneville Power Administration | FNO |
| 26 | Bonneville Power Administration | Bonneville Power Administration | Bonneville Power Administration | AD |
| 27 | Bonneville Power Administration | | | NF |
| 28 | Bonneville Power Administration | | | AD |
| 29 | Bonneville Power Administration | Bonneville Power Administration | Clark PUD | FNO |
| 30 | Bonneville Power Administration | Bonneville Power Administration | Clark PUD | AD |
| 31 | Cargill-Alliant, LLC | | | NF |
| 32 | Cargill-Alliant, LLC | | | AD |
| 33 | Cargill-Alliant, LLC | | | SFP |
| 34 | CitiGroup Energy Inc. | | | NF |
| | TOTAL | | | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

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

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

| FERC Rate Schedule of Tariff Number (e) | Point of Receipt (Subsatation or Other Designation) (f) | Point of Delivery (Substation or Other Designation) (g) | Billing Demand (MW) (h) | TRANSFER OF ENERGY MegaWatt Hours Received (i) | TRANSFER OF ENERGY MegaWatt Hours Delivered (j) | Line No. |
|---|---|---|---|---|---|---|
| 7V11- 3 & 4 | Yellowtail Sub | Sheridan Sub | 10 | 85,567 | 85,567 | 1 |
| 7V11- 3 & 4 | Yellowtail Sub | Sheridan Sub | | 7,762 | 7,762 | 2 |
| 7V11- 3 & 4 | Yellowtail Sub | Sheridan Sub | 8 | 54,941 | 54,941 | 3 |
| 7V11- 3 & 4 | Yellowtail Sub | Sheridan Sub | | 5,777 | 5,777 | 4 |
| 7V11- 8 | Various | Various | | 35,028 | 35,028 | 5 |
| 7V11- 8 | Various | Various | | | | 6 |
| 7V11- 8 | Various | Various | | 50,993 | 50,993 | 7 |
| 7V11- 8 | Various | Various | | 1,637 | 1,637 | 8 |
| 7V11 | Various | Sheridan Sub | 40 | 147,015 | 147,015 | 9 |
| 7V11 | Various | Sheridan Sub | | 6,982 | 6,982 | 10 |
| S.A. 67 | Various | Wyodak Sub | 50 | 244,804 | 244,804 | 11 |
| S.A. 67 | Various | Wyodak Sub | | 23,559 | 23,559 | 12 |
| S.A. 237 | Various | Various | 310 | 1,474,347 | 1,474,347 | 13 |
| S.A. 237 | Various | Various | | 152,559 | 152,559 | 14 |
| S.A. 324 | Lost Creek Hydro | Various | | 273,429 | 273,429 | 15 |
| S.A. 324 | Lost Creek Hydro | Various | | 20,412 | 20,412 | 16 |
| 7V11- 3 | Bonneville Power Adm | Gazley Substation | 3 | 21,774 | 21,774 | 17 |
| 7V11- 3 | Bonneville Power Adm | Gazley Substation | | 2,204 | 2,204 | 18 |
| 7V11- 7 | USBR Green Springs | Bonneville Power Adm | | 61,128 | 61,128 | 19 |
| 7V11- 7 | USBR Green Springs | Bonneville Power Adm | | 3,503 | 3,503 | 20 |
| S.A. 368 | Malin Sub | Malin Sub | 102 | 666,863 | 666,863 | 21 |
| S.A. 368 | Malin Sub | Malin Sub | | | | 22 |
| 7V11- 3 & 4 | Bonneville Power Adm | White Swan/Toppenish | 7 | 35,173 | 35,173 | 23 |
| 7V11- 3 & 4 | Bonneville Power Adm | White Swan/Toppenish | | 3,003 | 3,003 | 24 |
| S.A. 299 | Various | Various | 217 | 1,533,152 | 1,533,152 | 25 |
| S.A. 299 | Various | Various | | 219,708 | 219,708 | 26 |
| 7V11- 8 & 11 | Various | Various | | | | 27 |
| 7V11- 8 | Various | Various | | 720 | 720 | 28 |
| 7V11- 3 & 4 | Cardwell-Merwin | Chelatchie/View | 24 | 112,580 | 112,580 | 29 |
| 7V11- 3 & 4 | Cardwell-Merwin | Chelatchie/View | | 12,017 | 12,017 | 30 |
| 7V11- 8 & 11 | Various | Various | | 742,082 | 742,082 | 31 |
| 7V11- 8 | Various | Various | | 12,458 | 12,458 | 32 |
| 7V11- 7 | Various | Various | | 132,776 | 132,776 | 33 |
| 7V11- 8 | Various | Various | | 1,105 | 1,105 | 34 |
| | | | **2,380** | **17,170,080** | **17,170,080** | |

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(Next Page is 330)

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

### REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

| Demand Charges ($) (k) | Energy Charges ($) (l) | (Other Charges) ($) (m) | Total Revenues ($) (k+l+m) (n) | Line No. |
|---|---|---|---|---|
| 185,931 | | 57,786 | 243,717 | 1 |
| | | 17,141 | 17,141 | 2 |
| 187,515 | | | 187,515 | 3 |
| 18,433 | | 6,324 | 24,757 | 4 |
| | 228,819 | | 228,819 | 5 |
| | 105 | | 105 | 6 |
| | 313,279 | | 313,279 | 7 |
| | | 9,840 | 9,840 | 8 |
| 668,737 | | | 668,737 | 9 |
| | | 62,724 | 62,724 | 10 |
| 1,113,750 | | | 1,113,750 | 11 |
| | | 101,250 | 101,250 | 12 |
| 4,033,635 | | 67,947 | 4,101,582 | 13 |
| | | 370,307 | 370,307 | 14 |
| 286,253 | | | 286,253 | 15 |
| | | 26,023 | 26,023 | 16 |
| 46,718 | | 132,199 | 178,917 | 17 |
| | | 39,951 | 39,951 | 18 |
| 400,950 | | | 400,950 | 19 |
| | | 36,450 | 36,450 | 20 |
| | | 246,945 | 246,945 | 21 |
| | | 22,450 | 22,450 | 22 |
| 84,442 | | 102,347 | 186,789 | 23 |
| | | 38,682 | 38,682 | 24 |
| 1,026,833 | | 1,024,573 | 2,051,406 | 25 |
| | | 189,164 | 189,164 | 26 |
| | 12,335 | 138 | 12,473 | 27 |
| | | 4,205 | 4,205 | 28 |
| 375,736 | | 23,798 | 399,534 | 29 |
| | | 38,070 | 38,070 | 30 |
| | 4,147,151 | 28,558 | 4,175,709 | 31 |
| | | 96,481 | 96,481 | 32 |
| | 651,379 | | 651,379 | 33 |
| | 11,119 | | 11,119 | 34 |
| **26,628,319** | **19,473,259** | **29,451,666** | **75,553,244** | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

| Line No. | Payment By (Company of Public Authority) (Footnote Affiliation) (a) | Energy Received From (Company of Public Authority) (Footnote Affiliation) (b) | Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c) | Statistical Classification (d) |
|---|---|---|---|---|
| 1 | CitiGroup Energy Inc. | | | AD |
| 2 | Conoco Inc. | | | NF |
| 3 | Constellation Power | | | NF |
| 4 | Constellation Power | | | SFP |
| 5 | Coral Power | | | NF |
| 6 | Cowlitz County PUD | Cowlitz County PUD | Bonneville Power Administration | OS |
| 7 | Cowlitz County PUD | Cowlitz County PUD | Bonneville Power Administration | AD |
| 8 | Deseret Generation & Transmission | | | NF |
| 9 | Deseret Generation & Transmission | | | SFP |
| 10 | Deseret Generation & Transmission | Deseret Generation & Transmission | Deseret Generation & Transmission | OS |
| 11 | Deseret Generation & Transmission | Deseret Generation & Transmission | Deseret Generation & Transmission | AD |
| 12 | Eugene Water & Electric Board | Eugene Water & Electric Board | Grant County PUD | LFP |
| 13 | Eugene Water & Electric Board | Eugene Water & Electric Board | Grant County PUD | AD |
| 14 | Eugene Water & Electric Board | | | NF |
| 15 | Eugene Water & Electric Board | | | AD |
| 16 | Fall River Rural Electric Coop. | Marysville Hydro Partners | Idaho Power Company | OLF |
| 17 | Fall River Rural Electric Coop. | Marysville Hydro Partners | Idaho Power Company | AD |
| 18 | Flathead Electric Cooperative Inc. | Western Area Power Administration | Flathead Electric Coop., Inc. | FNO |
| 19 | Flathead Electric Cooperative Inc. | Western Area Power Administration | Flathead Electric Coop., Inc. | AD |
| 20 | Highland Energy LLC | | | NF |
| 21 | Iberdrola Renewables Inc. | | | NF |
| 22 | Iberdrola Renewables Inc. | | | AD |
| 23 | Iberdrola Renewables Inc. | Stateline Wind | Stateline Wind | OS |
| 24 | Iberdrola Renewables Inc. | Stateline Wind | Stateline Wind | AD |
| 25 | Iberdrola Renewables Inc. | Uinta | Uinta | OS |
| 26 | Iberdrola Renewables Inc. | Uinta | Uinta | AD |
| 27 | Iberdrola Renewables Inc. | Exxon Mobile | Nevada/Los Angeles | LFP |
| 28 | Iberdrola Renewables Inc. | Exxon Mobile | Nevada/Los Angeles | AD |
| 29 | Idaho Power Company | Nevada Power Company | Idaho Power Company | LFP |
| 30 | Idaho Power Company | | | SFP |
| 31 | Idaho Power Company | | | NF |
| 32 | Idaho Power Company | | | AD |
| 33 | Idaho Power Company | | | OLF |
| 34 | Idaho Power Company | | | AD |
| | **TOTAL** | | | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

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

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

| FERC Rate Schedule of Tariff Number (e) | Point of Receipt (Subsatation or Other Designation) (f) | Point of Delivery (Substation or Other Designation) (g) | Billing Demand (MW) (h) | TRANSFER OF ENERGY | | Line No. |
|---|---|---|---|---|---|---|
| | | | | MegaWatt Hours Received (i) | MegaWatt Hours Delivered (j) | |
| 7V11- 8 | Various | Various | | 1 | 1 | 1 |
| 7V11- 8 | Various | Various | | 58 | 58 | 2 |
| 7V11- 8 | Various | Various | | 329,958 | 329,958 | 3 |
| 7V11- 7 & 11 | Various | Various | | 93,104 | 93,104 | 4 |
| 7V11- 8 | Various | Various | | 3,542 | 3,542 | 5 |
| S.A. 234 | Swift Unit No. 2 | Woodland Sub | | | | 6 |
| S.A. 234 | Swift Unit No. 2 | Woodland Sub | | | | 7 |
| 7V11- 8 | Various | Various | | | | 8 |
| 7V11- 7 | Various | Various | | | | 9 |
| S.A. 280 | Various | Various | 105 | 1,579,211 | 1,579,211 | 10 |
| S.A. 280 | Various | Various | 105 | 149,101 | 149,101 | 11 |
| 7V11- 5,7,9 | Tieton Sub | Various | 15 | 5,236 | 5,236 | 12 |
| 7V11- 7 | Tieton Sub | Various | | | | 13 |
| 7V11- 8 | Various | Various | | 358 | 358 | 14 |
| 7V11- 8 | Various | Various | | 627 | 627 | 15 |
| S.A. 322 | Targhee Sub | Goshen Sub | 9 | | | 16 |
| S.A. 322 | Targhee Sub | Goshen Sub | | | | 17 |
| 7V11- 3 | Yellowtail Sub | Various | 1 | 4,585 | 4,585 | 18 |
| 7V11- 3 | Yellowtail Sub | Various | | 499 | 499 | 19 |
| 7V11- 8 | Various | Various | | 87 | 87 | 20 |
| 7V11- 8 | Various | Various | | 192,109 | 192,109 | 21 |
| 7V11- 8 | Various | Various | | 62,149 | 62,149 | 22 |
| 7V11- 5,9,11 | Various | Various | | | | 23 |
| 7V11- 5 & 9 | Various | Various | | | | 24 |
| 7V11- 5,9,11 | Various | Various | | | | 25 |
| 7V11- 5 & 9 | Various | Various | | | | 26 |
| 7V11- 7 | Exxon Metering Sta. | Harry Allen/Mona Sub | 75 | 137,485 | 137,485 | 27 |
| 7V11- 7 | Exxon Metering Sta. | Harry Allen/Mona Sub | | 80,687 | 80,687 | 28 |
| 7V11- 7 | Various | Various | | 110,111 | 110,111 | 29 |
| 7V11- 7 | Various | Various | | 18,089 | 18,089 | 30 |
| 7V11- 8 | Various | Various | | 78,082 | 78,082 | 31 |
| 7V11- 8 | Various | Various | | 1,889 | 1,889 | 32 |
| S.A. 257 | Antelope Sub | Antelope Sub | | | | 33 |
| S.A. 257 | Antelope Sub | Antelope Sub | | | | 34 |
| | | | **2,380** | **17,170,080** | **17,170,080** | |

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(Next Page is 330.1)

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

| Demand Charges ($) (k) | Energy Charges ($) (l) | (Other Charges) ($) (m) | Total Revenues ($) (k+l+m) (n) | Line No. |
|---|---|---|---|---|
| | | 6 | 6 | 1 |
| | 818 | | 818 | 2 |
| | 2,028,883 | | 2,028,883 | 3 |
| | 543,911 | 410,017 | 953,928 | 4 |
| | 32,061 | | 32,061 | 5 |
| 93,951 | | | 93,951 | 6 |
| | | 8,251 | 8,251 | 7 |
| | 631 | | 631 | 8 |
| | 5,022 | | 5,022 | 9 |
| 1,877,144 | | 1,411,239 | 3,288,383 | 10 |
| | | 163,120 | 163,120 | 11 |
| 121,500 | | 4,868 | 126,368 | 12 |
| | | 30,375 | 30,375 | 13 |
| | 21,713 | | 21,713 | 14 |
| | 3,662 | | 3,662 | 15 |
| | | 138,699 | 138,699 | 16 |
| | | 12,609 | 12,609 | 17 |
| 12,187 | | 27,456 | 39,643 | 18 |
| | | 3,921 | 3,921 | 19 |
| | 987 | | 987 | 20 |
| | 1,598,297 | | 1,598,297 | 21 |
| | 189,801 | 231,235 | 421,036 | 22 |
| | | 83,885 | 83,885 | 23 |
| | | 43,696 | 43,696 | 24 |
| | | 198,761 | 198,761 | 25 |
| | | 101,907 | 101,907 | 26 |
| 1,215,000 | | | 1,215,000 | 27 |
| 455,625 | | 151,875 | 607,500 | 28 |
| 748,012 | | | 748,012 | 29 |
| | 911,250 | | 911,250 | 30 |
| | 196,897 | 7,440 | 204,337 | 31 |
| | | 9,806 | 9,806 | 32 |
| | | 67,672 | 67,672 | 33 |
| | | 6,152 | 6,152 | 34 |
| **26,628,319** | **19,473,259** | **29,451,666** | **75,553,244** | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

| Line No. | Payment By (Company of Public Authority) (Footnote Affiliation) (a) | Energy Received From (Company of Public Authority) (Footnote Affiliation) (b) | Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c) | Statistical Classification (d) |
|---|---|---|---|---|
| 1 | Idaho Power Company | | | OLF |
| 2 | Idaho Power Company | | | AD |
| 3 | Integrys Energy Services | | | NF |
| 4 | Integrys Energy Services | | | SFP |
| 5 | Intermountain Renewable Power LLC | Intermountain Renewable Power | Intermountain Renewable Power | LFP |
| 6 | Moon Lake Electric Association | Moon Lake Electric Association | Moon Lake Electric Association | OLF |
| 7 | Moon Lake Electric Association | Moon Lake Electric Association | Moon Lake Electric Association | AD |
| 8 | Municipal Energy Agency of Nebraska | | | NF |
| 9 | Morgan Stanley Capital Group, Inc. | | | NF |
| 10 | Morgan Stanley Capital Group, Inc. | | | AD |
| 11 | Nevada Power Company | | | NF |
| 12 | Pacific Gas & Electric | | | OS |
| 13 | Pacific Gas & Electric | | | OS |
| 14 | Portland General Electric | | | NF |
| 15 | Portland General Electric | | | AD |
| 16 | Powerex | Eugene Water & Electric Board | Grant County PUD | LFP |
| 17 | Powerex | Eugene Water & Electric Board | Grant County PUD | OS |
| 18 | Powerex | Bonneville Power Administration | CAISO | LFP |
| 19 | Powerex | Bonneville Power Administration | CAISO | AD |
| 20 | Powerex | | | NF |
| 21 | Powerex | | | AD |
| 22 | Powerex | | | SFP |
| 23 | Powerex | | | AD |
| 24 | Powder River Energy Corporation | Var. WAPA Interconnection in PACE | Sheridan Johnson Rural Elect. | OLF |
| 25 | Powder River Energy Corporation | Var. WAPA Interconnection in PACE | Sheridan Johnson Rural Elect. | AD |
| 26 | PPL Energy Plus | | | NF |
| 27 | PPL Energy Plus | | | AD |
| 28 | Public Service Company of Colorado | | | SFP |
| 29 | Public Service Company of Colorado | | | NF |
| 30 | Public Service Company of Colorado | | | AD |
| 31 | Rainbow Energy Marketing | | | SFP |
| 32 | Rainbow Energy Marketing | | | NF |
| 33 | Rainbow Energy Marketing | | | AD |
| 34 | Seattle City & Light | PacifiCorp Merchant | Grant County PUD | LFP |
| | TOTAL | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

| FERC Rate Schedule of Tariff Number (e) | Point of Receipt (Subsatation or Other Designation) (f) | Point of Delivery (Substation or Other Designation) (g) | Billing Demand (MW) (h) | TRANSFER OF ENERGY MegaWatt Hours Received (i) | MegaWatt Hours Delivered (j) | Line No. |
|---|---|---|---|---|---|---|
| S.A. 203 | Jim Bridger Sub | Bridger Pump Station | | | | 1 |
| S.A. 203 | Jim Bridger Sub | Bridger Pump Station | | | | 2 |
| 7V11- 8 | Various | Various | | 10,112 | 10,112 | 3 |
| 7V11- 7 | Various | Various | | 1,182 | 1,182 | 4 |
| S.A. 509 | Sigurd-345KV bus | Mona | 11 | | | 5 |
| S.A. 302 | Duchesne | Duchesne | 3 | 13,827 | 13,827 | 6 |
| S.A. 302 | Duchesne | Duchesne | 3 | 1,213 | 1,213 | 7 |
| 7V11- 8 | Various | Various | | 321 | 321 | 8 |
| 7V11- 8 | Various | Various | | 243,617 | 243,617 | 9 |
| 7V11- 8 | Various | Various | | 6,444 | 6,444 | 10 |
| 7V11- 8 | Various | Various | | 3,568 | 3,568 | 11 |
| S.A. 86 | Various | Various | | | | 12 |
| S.A. 298 | Sigurd-Glen Canyon | Pinto-Four Corners | | | | 13 |
| 7V11- 8 | Various | Various | | 1,642 | 1,642 | 14 |
| 7V11- 8 | Various | Various | | 15 | 15 | 15 |
| 7V11- 5,7,9 | Tieton Sub | Various | 15 | | | 16 |
| 7V11- 5,7,9 | Tieton Sub | Various | 15 | 38,339 | 38,339 | 17 |
| 7V11- 7 | Bonneville Power Adm | Weed Jct. Sub | 80 | 303,793 | 303,793 | 18 |
| 7V11- 7 | Bonneville Power Adm | Weed Jct. Sub | | 17,971 | 17,971 | 19 |
| 7V11- 8 | Various | Various | | 612,137 | 612,137 | 20 |
| 7V11- 8 | Various | Various | | 8,534 | 8,534 | 21 |
| 7V11- 7 | Various | Various | | 201,263 | 201,263 | 22 |
| 7V11- 7 | Various | Various | | 2,207 | 2,207 | 23 |
| S.A. 59 | Various | Buffalo Sub | | | | 24 |
| S.A. 59 | Various | Buffalo Sub | | | | 25 |
| 7V11- 8 | Various | Various | | 17,796 | 17,796 | 26 |
| 7V11- 8 | Various | Various | | 969 | 969 | 27 |
| 7V11- 7 | Various | Various | | 1,200 | 1,200 | 28 |
| 7V11- 8 | Various | Various | | 9,015 | 9,015 | 29 |
| 7V11- 8 | Various | Various | | 50 | 50 | 30 |
| 7V11- 7 | Various | Various | | 69,161 | 69,161 | 31 |
| 7V11- 8 | Various | Various | | 57,597 | 57,597 | 32 |
| 7V11- 8 | Various | Various | | 1,550 | 1,550 | 33 |
| 7V11- 7 | Wallula Sub | Mid-C | | | | 34 |
| | | | **2,380** | **17,170,080** | **17,170,080** | |

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(Next Page is 330.2)

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

### REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

| Demand Charges ($) (k) | Energy Charges ($) (l) | (Other Charges) ($) (m) | Total Revenues ($) (k+l+m) (n) | Line No. |
|---|---|---|---|---|
| | | 14,927 | 14,927 | 1 |
| | | 1,357 | 1,357 | 2 |
| | 62,130 | | 62,130 | 3 |
| | 6,568 | | 6,568 | 4 |
| | | 22,275 | 22,275 | 5 |
| 17,281 | | | 17,281 | 6 |
| 1,608 | | | 1,608 | 7 |
| | 1,939 | | 1,939 | 8 |
| | 1,678,539 | | 1,678,539 | 9 |
| | | 50,008 | 50,008 | 10 |
| | 44,249 | | 44,249 | 11 |
| | | 20,000,000 | 20,000,000 | 12 |
| | | 344,121 | 344,121 | 13 |
| | 11,680 | | 11,680 | 14 |
| | 88 | | 88 | 15 |
| 60,750 | | | 60,750 | 16 |
| | | 33,179 | 33,179 | 17 |
| 1,447,875 | | | 1,447,875 | 18 |
| | | 131,625 | 131,625 | 19 |
| | 3,180,320 | | 3,180,320 | 20 |
| | | 43,012 | 43,012 | 21 |
| | 822,549 | | 822,549 | 22 |
| | | 12,363 | 12,363 | 23 |
| | | 168 | 168 | 24 |
| | | 16 | 16 | 25 |
| | 104,991 | | 104,991 | 26 |
| | | 5,659 | 5,659 | 27 |
| | 4,650 | | 4,650 | 28 |
| | 39,425 | | 39,425 | 29 |
| | | 292 | 292 | 30 |
| | 437,651 | | 437,651 | 31 |
| | 321,169 | | 321,169 | 32 |
| | | 6,792 | 6,792 | 33 |
| | | 212,625 | 212,625 | 34 |
| **26,628,319** | **19,473,259** | **29,451,666** | **75,553,244** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

| Line No. | Payment By (Company of Public Authority) (Footnote Affiliation) (a) | Energy Received From (Company of Public Authority) (Footnote Affiliation) (b) | Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c) | Statistical Classification (d) |
|---|---|---|---|---|
| 1 | Seawest Windpower, Inc. | Foote Creek Sub | Foote Creek Sub | OLF |
| 2 | Seawest Windpower, Inc. | Foote Creek Sub | Foote Creek Sub | AD |
| 3 | Sempra Energy Trading Corp | | | NF |
| 4 | Sempra Energy Trading Corp | | | AD |
| 5 | Sempra Energy Solutions | Bonneville Power Administration | Oregon Direct Access | FNO |
| 6 | Sempra Energy Solutions | Bonneville Power Administration | Oregon Direct Access | AD |
| 7 | Shell Energy North America | | | NF |
| 8 | Sierra Pacific Power Company | | | NF |
| 9 | Sierra Pacific Power Company | | | AD |
| 10 | Sierra Pacific Power Company | | | SFP |
| 11 | Sierra Pacific Power Company | | | AD |
| 12 | Southern California Edison Company | | | OS |
| 13 | State of South Dakota | Western Area Power Administration | Black Hills Power & Light Company | LFP |
| 14 | State of South Dakota | Western Area Power Administration | Black Hills Power & Light Company | AD |
| 15 | TransAlta Energy | | | NF |
| 16 | TransAlta Energy | | | AD |
| 17 | Tri-State Generation & Transmission | | | OS |
| 18 | Tri-State Generation & Transmission | | | AD |
| 19 | Tri-State Generation & Transmission | | | SFP |
| 20 | Tri-State Generation & Transmission | | | NF |
| 21 | Tri-State Generation & Transmission | | | AD |
| 22 | United States Bureau of Reclamation | Bonneville Power Administration | U.S. Bureau of Reclamation | FNO |
| 23 | United States Bureau of Reclamation | Bonneville Power Administration | Crooked River Irrigation District | OLF |
| 24 | United States Bureau of Reclamation | Bonneville Power Administration | U.S. Bureau of Reclamation | OLF |
| 25 | United States Bureau of Reclamation | Bonneville Power Administration | U.S. Bureau of Reclamation | OLF |
| 26 | United States Bureau of Reclamation | Western Area Power Administration | Weber Basin | AD |
| 27 | Utah Associated Municipal Power | Utah Associated Municipal Power | Utah Associated Municipal Power | OS |
| 28 | Utah Associated Municipal Power | Utah Associated Municipal Power | Utah Associated Municipal Power | AD |
| 29 | Utah Municipal Power Agency | Utah Municipal Power Agency | Utah Municipal Power Agency | OS |
| 30 | Utah Municipal Power Agency | Utah Municipal Power Agency | Utah Municipal Power Agency | AD |
| 31 | Warm Springs Power Enterprises | Warm Springs Enterprises | Portland General Electric Co. | OLF |
| 32 | Warm Springs Power Enterprises | Warm Springs Enterprises | Portland General Electric Co. | AD |
| 33 | Western Area Power Administration | Western Area Power Administration | Various WAPA Customers in PACE | OS |
| 34 | Western Area Power Administration | Western Area Power Administration | Various WAPA Customers in PACE | AD |
| | TOTAL | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

| FERC Rate Schedule of Tariff Number (e) | Point of Receipt (Subsatation or Other Designation) (f) | Point of Delivery (Substation or Other Designation) (g) | Billing Demand (MW) (h) | TRANSFER OF ENERGY MegaWatt Hours Received (i) | TRANSFER OF ENERGY MegaWatt Hours Delivered (j) | Line No. |
|---|---|---|---|---|---|---|
| S.A. 264 | Foote Creek Sub | Various | | | | 1 |
| S.A. 264 | Foote Creek Sub | Various | | | | 2 |
| 7V11- 8 | Various | Various | | 2,000 | 2,000 | 3 |
| 7V11- 8 | Various | Various | | 9,902 | 9,902 | 4 |
| 7V11- 3 & 4 | Bonneville Power Adm | Various | 17 | 100,205 | 100,205 | 5 |
| 7V11- 3 & 4 | Bonneville Power Adm | Various | | 8,845 | 8,845 | 6 |
| 7V11- 8 | Various | Various | | 1,082 | 1,082 | 7 |
| 7V11- 8 | Various | Various | | 189,297 | 189,297 | 8 |
| 7V11- 8 | Various | Various | | 49,200 | 49,200 | 9 |
| 7V11- 7 | Various | Various | | 89,354 | 89,354 | 10 |
| 7V11- 7 | Various | Various | | 68,998 | 68,998 | 11 |
| S.A. 86 | Malin Sub | Indian Springs | | | | 12 |
| 7V11- 7 | Yellowtail Sub | Wyodak Sub | 4 | 16,965 | 16,965 | 13 |
| 7V11- 7 | Yellowtail Sub | Wyodak Sub | | 1,384 | 1,384 | 14 |
| 7V11- 8 | Various | Various | | 53,508 | 53,508 | 15 |
| 7V11- 8 | Various | Various | | | | 16 |
| S.A. 123 | Various | Various | 31 | 157,189 | 157,189 | 17 |
| S.A. 123 | Various | Various | | 16,433 | 16,433 | 18 |
| 7V11- 7 | Various | Various | | 8,942 | 8,942 | 19 |
| 7V11- 8 | Various | Various | | 6,058 | 6,058 | 20 |
| 7V11- 8 | Various | Various | | 60 | 60 | 21 |
| S.A. 35 | Walla Walla Sub | Burbank Pumps | | | | 22 |
| R.S. 67 | Redmond Substation | Crooked River Pumps | | 10,277 | 10,277 | 23 |
| S.A. 67 | Pasco Sub | Dodd Road Sub | | | | 24 |
| S.A. 286 | Pasco Sub | Dodd Road Sub | | 30,173 | 30,173 | 25 |
| S.A. 286 | Various | Various | | 1,465 | 1,465 | 26 |
| S.A. 297 | Various | Various | 338 | 3,035,988 | 3,035,988 | 27 |
| S.A. 297 | Various | Various | | 290,889 | 290,889 | 28 |
| S.A. 279 | Various | Various | 109 | 574,223 | 574,223 | 29 |
| S.A. 279 | Various | Various | | 52,186 | 52,186 | 30 |
| S.A. 591 | Pelton Reregulating | Round Butte Sub | 16 | 75,932 | 75,932 | 31 |
| S.A. 591 | Pelton Reregulating | Round Butte Sub | | 7,511 | 7,511 | 32 |
| S.A. 262 & 263 | Various | Various | 328 | 1,534,091 | 1,534,091 | 33 |
| S.A. 262 & 263 | Various | Various | 328 | 150,370 | 150,370 | 34 |
| | | | **2,380** | **17,170,080** | **17,170,080** | |

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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

| Demand Charges ($) (k) | Energy Charges ($) (l) | (Other Charges) ($) (m) | Total Revenues ($) (k+l+m) (n) | Line No. |
|---|---|---|---|---|
| | | 33,168 | 33,168 | 1 |
| | | -37,833 | -37,833 | 2 |
| | 11,658 | | 11,658 | 3 |
| | | 48,545 | 48,545 | 4 |
| 137,289 | | 20,950 | 158,239 | 5 |
| 11,541 | | 1,533 | 13,074 | 6 |
| | 8,194 | | 8,194 | 7 |
| | 906,708 | | 906,708 | 8 |
| | | 110,564 | 110,564 | 9 |
| | 393,161 | | 393,161 | 10 |
| | | 253,125 | 253,125 | 11 |
| | | 344,121 | 344,121 | 12 |
| 89,100 | | | 89,100 | 13 |
| | | 8,100 | 8,100 | 14 |
| | 207,512 | | 207,512 | 15 |
| | 29 | | 29 | 16 |
| 97,576 | | | 97,576 | 17 |
| | | 3,559 | 3,559 | 18 |
| | 54,845 | | 54,845 | 19 |
| | 40,991 | | 40,991 | 20 |
| | | 350 | 350 | 21 |
| | | 3,505 | 3,505 | 22 |
| 12,095 | 1,581 | | 13,676 | 23 |
| | | 60 | 60 | 24 |
| 30,173 | | | 30,173 | 25 |
| | | 1,465 | 1,465 | 26 |
| 7,078,025 | | 302,156 | 7,380,181 | 27 |
| | | 607,687 | 607,687 | 28 |
| 1,979,022 | | 98,395 | 2,077,417 | 29 |
| | | 180,341 | 180,341 | 30 |
| 109,725 | | | 109,725 | 31 |
| | | 9,975 | 9,975 | 32 |
| 2,582,163 | | | 2,582,163 | 33 |
| | | 228,784 | 228,784 | 34 |
| **26,628,319** | **19,473,259** | **29,451,666** | **75,553,244** | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

| Line No. | Payment By (Company of Public Authority) (Footnote Affiliation) (a) | Energy Received From (Company of Public Authority) (Footnote Affiliation) (b) | Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c) | Statistical Classification (d) |
|---|---|---|---|---|
| 1 | Western Area Power Administration | Western Area Power Administration | Various WAPA Customers in PACE | NF |
| 2 | Western Area Power Administration | Western Area Power Administration | Various WAPA Customers in PACE | SFP |
| 3 | Western Area Power Administration | Western Area Power Administration | Various WAPA Customers in PACE | AD |
| 4 | Western Area Power Administration | Western Area Power Administration | Western Area Power Administration | FNO |
| 5 | Western Area Power Administration | Western Area Power Administration | Western Area Power Administration | AD |
| 6 | Accrual True-up | | | |
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| 8 | | | | |
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| 32 | | | | |
| 33 | | | | |
| 34 | | | | |
| | TOTAL | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

| FERC Rate Schedule of Tariff Number (e) | Point of Receipt (Subsatation or Other Designation) (f) | Point of Delivery (Substation or Other Designation) (g) | Billing Demand (MW) (h) | TRANSFER OF ENERGY | | Line No. |
|---|---|---|---|---|---|---|
| | | | | MegaWatt Hours Received (i) | MegaWatt Hours Delivered (j) | |
| 7V11- 8 | Various | Various | | 870 | 870 | 1 |
| 7V11- 7 | Various | Various | | | | 2 |
| 7V11- 8 | Various | Various | | 1,048 | 1,048 | 3 |
| 7V11 | Wyoming Distribution | Wyoming Distribution | 1 | 10,085 | 10,085 | 4 |
| 7V11 | Wyoming Distribution | Various | | 1 | 1 | 5 |
| | | | | | | 6 |
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| | | | | | | 34 |
| | | | 2,380 | 17,170,080 | 17,170,080 | |

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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

### REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

| Demand Charges ($) (k) | Energy Charges ($) (l) | (Other Charges) ($) (m) | Total Revenues ($) (k+l+m) (n) | Line No. |
|---|---|---|---|---|
| | 227,537 | | 227,537 | 1 |
| | 6,975 | | 6,975 | 2 |
| | | 7,265 | 7,265 | 3 |
| 21,744 | | 33,037 | 54,781 | 4 |
| | | 11,208 | 11,208 | 5 |
| | | 446,844 | 446,844 | 6 |
| | | | | 7 |
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| | | | | 33 |
| | | | | 34 |
| **26,628,319** | **19,473,259** | **29,451,666** | **75,553,244** | |

**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 and 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**

Charges for monitoring, scheduling, load following and spinning reserve. Regulation & Frequency Response. December 2007 Service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

**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**

Regulation & Frequency Response. December 2007 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.: 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.: 8 Column: m**

December 2007 Service.

**Schedule Page: 328 Line No.: 9 Column: d**

Network Transmission Service under the Open Access Transmission Tariff (S.A. 347) terminating on December 31, 2017.

**Schedule Page: 328 Line No.: 10 Column: d**

Network Transmission Service under the Open Access Transmission Tariff (S.A. 347) terminating on December 31, 2017.

**Schedule Page: 328 Line No.: 10 Column: m**

December 2007 Service.

**Schedule Page: 328 Line No.: 11 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.: 12 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.: 12 Column: m**

December 2007 Service.

**Schedule Page: 328 Line No.: 13 Column: d**

General Transfer Agreement for network service in PACW. Evergreen.

**Schedule Page: 328 Line No.: 13 Column: m**

Demand dollars plus a fixed cost calculated using plant investment values at various U.S. government facilities.

**Schedule Page: 328 Line No.: 14 Column: d**

General Transfer Agreement for network service in PACW. Evergreen.

**Schedule Page: 328 Line No.: 14 Column: m**

Demand dollars plus a fixed cost calculated using plant investment values at various U.S. government facilities. December 2007 Service and 2007 adjustments.

**Schedule Page: 328 Line No.: 15 Column: d**

Network Transmission Service terminating with one year's written notice.

**Schedule Page: 328 Line No.: 16 Column: d**

Network Transmission Service terminating with one year's written notice.

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

December 2007 Service.

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

Distribution Service Charge. Primary Delivery Service. Regulation & Frequency Response.

**Schedule Page: 328 Line No.: 18 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.: 18 Column: m**

Regulation & Frequency Response. December 2007 Service. Distribution Service Charge and Primary Delivery Service - October to December 2007.

**Schedule Page: 328 Line No.: 19 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.: 20 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.: 20 Column: m**

December 2007 Service.

**Schedule Page: 328 Line No.: 21 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.: 21 Column: m**

Sole use of facilities charge.

**Schedule Page: 328 Line No.: 22 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.: 22 Column: m**

December 2007 Service.

**Schedule Page: 328 Line No.: 23 Column: d**

Network Transmission Service and Distribution Delivery Service under the Open Access Transmission Tariff (S.A. 328) terminating on September 30, 2011.

**Schedule Page: 328 Line No.: 23 Column: m**

Distribution Service Charge. Primary Delivery Service. Regulation & Frequency Response. Penalty revenues covering imbalance charges per Schedules 4 and 9.

**Schedule Page: 328 Line No.: 24 Column: d**

Network Transmission Service and Distribution Delivery Service under the Open Access Transmission Tariff (S.A. 328) terminating on September 30, 2011.

**Schedule Page: 328 Line No.: 24 Column: m**

Regulation & Frequency Response. December 2007 Service. Penalty revenues covering imbalance charges per Schedules 4 and 9. Distribution Service Charge and Primary Delivery Service - October to December 2007.

**Schedule Page: 328 Line No.: 25 Column: d**

General Transfer Agreement for network service in PACE. Evergreen.

**Schedule Page: 328 Line No.: 25 Column: m**

Sole use of facilities charge. Charges for monitoring, scheduling, load following and spinning reserve.

**Schedule Page: 328 Line No.: 26 Column: d**

General Transfer Agreement for network service in PACE. Evergreen.

**Schedule Page: 328 Line No.: 26 Column: m**

Sole use of facilities charge. December 2007 Service.

**Schedule Page: 328 Line No.: 27 Column: b**

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

**Schedule Page: 328 Line No.: 27 Column: c**

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

**Schedule Page: 328 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 Line No.: 27 Column: m**

Unauthorized Use of Transmission Service.

**Schedule Page: 328 Line No.: 28 Column: b**

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

**Schedule Page: 328 Line No.: 28 Column: c**

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

**Schedule Page: 328 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 Line No.: 28 Column: m**

December 2007 Service.

**Schedule Page: 328 Line No.: 29 Column: d**

Network Transmission Service under the Open Access Transmission Tariff (S.A. 370) terminating on December 7, 2012 or with 6 month written notice.

**Schedule Page: 328 Line No.: 29 Column: m**

Regulation and Frequency Response. Penalty revenues covering imbalance charges per Schedules 4 and 9.

**Schedule Page: 328 Line No.: 30 Column: d**

Network Transmission Service under the Open Access Transmission Tariff (S.A. 370) terminating on December 7, 2012 or with 6 month written notice.

**Schedule Page: 328 Line No.: 30 Column: m**

Unauthorized Use of Transmission Service and refunds . Regulation & Frequency Response. December 2007 Service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

**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.: 31 Column: m**

Unauthorized Use of Transmission Service.

**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 2007 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.: 1 Column: m***

December 2007 Service.

***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: b***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.1 Line No.: 3 Column: c***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.1 Line No.: 3 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.: 4 Column: b***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.1 Line No.: 4 Column: c***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.1 Line No.: 4 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.: 4 Column: m***

Charges for monitoring, scheduling, load following and spinning reserve. Unauthorized Use of Transmission Service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

***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***

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.: 7 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.: 7 Column: m***

December 2007 Service.

***Schedule Page: 328.1 Line No.: 8 Column: b***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.1 Line No.: 8 Column: c***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.1 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: 328.1 Line No.: 9 Column: b***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.1 Line No.: 9 Column: c***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.1 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: 328.1 Line No.: 10 Column: d***

Transmission Service and Operating Agreement for network service in PACE. Subject to termination upon mutual agreement.

***Schedule Page: 328.1 Line No.: 10 Column: m***

Charges for monitoring, scheduling, load following and spinning reserve. Distribution Service Charge. Regulation & Frequency Response. Meter Interrogation Services.

***Schedule Page: 328.1 Line No.: 11 Column: d***

Transmission Service and Operating Agreement for network service in PACE. Subject to termination upon mutual agreement.

***Schedule Page: 328.1 Line No.: 11 Column: m***

Charges for monitoring, scheduling, load following and spinning reserve. Distribution Service Charge. Regulation & Frequency Response. Meter Interrogation Services. December 2007 Service. 2006 transmission services and ancillary services settlement adjustments.

***Schedule Page: 328.1 Line No.: 12 Column: d***

Transmission Service under the Open Access Transmission Tariff (S.A. 332).

***Schedule Page: 328.1 Line No.: 12 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.: 13 Column: d***

Transmission Service under the Open Access Transmission Tariff (S.A. 332).

***Schedule Page: 328.1 Line No.: 13 Column: m***

December 2007 Service.

***Schedule Page: 328.1 Line No.: 14 Column: b***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.1 Line No.: 14 Column: c***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.1 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: 328.1 Line No.: 15 Column: b***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.1 Line No.: 15 Column: c***

| Name of Respondent | This Report is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) X An Original<br>(2) _ A Resubmission | 03/31/2009 | 2008/Q4 |

FOOTNOTE DATA

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.1 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: 328.1 Line No.: 16 Column: d***

Point-to-Point Transmission Service terminating on July 31, 2028.

***Schedule Page: 328.1 Line No.: 16 Column: m***

Sole use of facilities charge.

***Schedule Page: 328.1 Line No.: 17 Column: d***

Point-to-Point Transmission Service terminating on July 31, 2028.

***Schedule Page: 328.1 Line No.: 17 Column: m***

Sole use of facilities charge. December 2007 Service.

***Schedule Page: 328.1 Line No.: 18 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.: 18 Column: m***

Distribution Service Charge. Primary Delivery Service. Regulation & Frequency Response.

***Schedule Page: 328.1 Line No.: 19 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.: 19 Column: m***

Distribution Service Charge. Primary Delivery Service. Regulation & Frequency Response. December 2007 Service.

***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.: 21 Column: b***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.1 Line No.: 21 Column: c***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.1 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: 328.1 Line No.: 22 Column: b***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.1 Line No.: 22 Column: c***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.1 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: 328.1 Line No.: 22 Column: m***

December 2007 Service.

***Schedule Page: 328.1 Line No.: 23 Column: d***

Ancillary Services under the Open Access Transmission Tariff (S.A. 313) in effect until superceded.

***Schedule Page: 328.1 Line No.: 23 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: 328.1 Line No.: 24 Column: d***

Ancillary Services under the Open Access Transmission Tariff (S.A. 313) in effect until superceded.

***Schedule Page: 328.1 Line No.: 24 Column: m***

Charges for monitoring, scheduling, load following and spinning reserve. Unauthorized Use of Transmission Service and refunds. December 2007 Service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

***Schedule Page: 328.1 Line No.: 25 Column: d***

Ancillary Services under the Open Access Transmission Tariff (S.A. 315) in effect until superceded.

***Schedule Page: 328.1 Line No.: 25 Column: m***

Charges for monitoring, scheduling, load following and spinning reserve. Unauthorized Use of Transmission Service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

***Schedule Page: 328.1 Line No.: 26 Column: d***

Ancillary Services under the Open Access Transmission Tariff (S.A. 315) in effect until superceded.

***Schedule Page: 328.1 Line No.: 26 Column: m***

Charges for monitoring, scheduling, load following and spinning reserve. Unauthorized Use of Transmission Service and refunds. December 2007 Service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

***Schedule Page: 328.1 Line No.: 27 Column: d***

Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 279). Terminates April 30, 2009.

***Schedule Page: 328.1 Line No.: 28 Column: d***

Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 279). Terminates April 30, 2009.

***Schedule Page: 328.1 Line No.: 28 Column: m***

December 2007 Service.

***Schedule Page: 328.1 Line No.: 29 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.: 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***

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***

Unauthorized Use of Transmission Service and refunds.

***Schedule Page: 328.1 Line No.: 32 Column: b***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.1 Line No.: 32 Column: c***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.1 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: 328.1 Line No.: 32 Column: m***

December 2007 Service.

***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 - Antelope Substation (S.A. 257) terminating coterminous with the Idaho/USDOE Supply Agreement.

***Schedule Page: 328.1 Line No.: 33 Column: m***

Sole use of facilities charge.

***Schedule Page: 328.1 Line No.: 34 Column: b***

Operation, maintenance or facility lease services with no receipt or delivery of energy.

***Schedule Page: 328.1 Line No.: 34 Column: c***

Operation, maintenance or facility lease services with no receipt or delivery of energy.

***Schedule Page: 328.1 Line No.: 34 Column: d***

Use of Facilities Agreement - Antelope Substation (S.A. 257) terminating coderminous with the Idaho/USDOE Supply Agreement.

***Schedule Page: 328.1 Line No.: 34 Column: m***

Sole use of facilities charge. December 2007 Service.

***Schedule Page: 328.2 Line No.: 1 Column: b***

Operation, maintenance or facility lease services with no receipt or delivery of energy.

***Schedule Page: 328.2 Line No.: 1 Column: c***

Operation, maintenance or facility lease services with no receipt or delivery of energy.

***Schedule Page: 328.2 Line No.: 1 Column: d***

Use of Facilities Agreement - Jim Bridger Pump (S.A. 203) - termination upon 12-month written notice.

***Schedule Page: 328.2 Line No.: 1 Column: m***

Sole use of facilities charge.

***Schedule Page: 328.2 Line No.: 2 Column: b***

Operation, maintenance or facility lease services with no receipt or delivery of energy.

***Schedule Page: 328.2 Line No.: 2 Column: c***

Operation, maintenance or facility lease services with no receipt or delivery of energy.

***Schedule Page: 328.2 Line No.: 2 Column: d***

Use of Facilities Agreement - Jim Bridger Pump (S.A. 203) - termination upon 12-month written notice.

***Schedule Page: 328.2 Line No.: 2 Column: m***

Sole use of facilities charge. December 2007 Service.

***Schedule Page: 328.2 Line No.: 3 Column: b***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.2 Line No.: 3 Column: c***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.2 Line No.: 3 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.: 4 Column: b***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.2 Line No.: 4 Column: c***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.2 Line No.: 4 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.: 5 Column: d***

Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 509) terminating September 14, 2029.

***Schedule Page: 328.2 Line No.: 5 Column: m***

Extension of Commencement Date Fee.

***Schedule Page: 328.2 Line No.: 6 Column: d***

Transmission Service and Interconnection Agreement for network service in PACE. Terminates in 2047.

***Schedule Page: 328.2 Line No.: 7 Column: d***

Transmission Service and Interconnection Agreement for network service in PACE. Terminates in 2047.

***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.: 10 Column: b***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.2 Line No.: 10 Column: c***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.2 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: 328.2 Line No.: 10 Column: m***

December 2007 Service.

***Schedule Page: 328.2 Line No.: 11 Column: b***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.2 Line No.: 11 Column: c***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.2 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: 328.2 Line No.: 12 Column: b***

Malin to Indian Springs Facilities lease (S.A. 607). Terminating December 31, 2017.

***Schedule Page: 328.2 Line No.: 12 Column: c***

Malin to Indian Springs Facilities lease (S.A. 607). Terminating December 31, 2017.

***Schedule Page: 328.2 Line No.: 12 Column: d***

Malin to Indian Springs Facilities lease (S.A. 607). Terminating December 31, 2017.

***Schedule Page: 328.2 Line No.: 12 Column: m***

Sole use of facilities charge.

***Schedule Page: 328.2 Line No.: 13 Column: b***

Operation, maintenance or facility lease services with no receipt or delivery of energy.

***Schedule Page: 328.2 Line No.: 13 Column: c***

Operation, maintenance or facility lease services with no receipt or delivery of energy.

***Schedule Page: 328.2 Line No.: 13 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: 328.2 Line No.: 13 Column: m***

Sole use of facilities charge.

***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.: 16 Column: d***

Transmission Service under the Open Access Transmission Tariff (S.A. 332).

***Schedule Page: 328.2 Line No.: 17 Column: d***

Transmission Service under the Open Access Transmission Tariff (S.A. 332).

***Schedule Page: 328.2 Line No.: 17 Column: m***

Charges for monitoring, scheduling, load following and spinning reserve. Penalty revenues covering imbalance charges per Schedules 4 and 9.

***Schedule Page: 328.2 Line No.: 18 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 March 1, 2009.

***Schedule Page: 328.2 Line No.: 19 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 March 1, 2009.

***Schedule Page: 328.2 Line No.: 19 Column: m***

December 2007 Service.

***Schedule Page: 328.2 Line No.: 20 Column: b***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.2 Line No.: 20 Column: c***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***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.: 21 Column: m***

December 2007 Service.

***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***

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.: 23 Column: b***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.2 Line No.: 23 Column: c***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.2 Line No.: 23 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.: 23 Column: m***

December 2007 Service.

***Schedule Page: 328.2 Line No.: 24 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.: 24 Column: m***

Sole use of facilities charge.

***Schedule Page: 328.2 Line No.: 25 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.: 25 Column: m***

Sole use of facilities charge. December 2007 Service.

***Schedule Page: 328.2 Line No.: 26 Column: b***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.2 Line No.: 26 Column: c***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.2 Line No.: 26 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.: 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.: 27 Column: m***

December 2007 Service.

***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.: 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: b***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.2 Line No.: 30 Column: c***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.2 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: 328.2 Line No.: 30 Column: m***

December 2007 Service.

***Schedule Page: 328.2 Line No.: 31 Column: b***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.2 Line No.: 31 Column: c***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.2 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: 328.2 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 2007 Service.

***Schedule Page: 328.2 Line No.: 34 Column: d***

Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 289) terminating November 30, 2009.

***Schedule Page: 328.2 Line No.: 34 Column: m***

Extension of Commencement Date Fee.

| Name of Respondent | This Report is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) X An Original<br>(2) _ A Resubmission | 03/31/2009 | 2008/Q4 |

FOOTNOTE DATA

***Schedule Page: 328.3 Line No.: 1 Column: d***

Use of Facilities (S.A. 264) terminating July 2014.

***Schedule Page: 328.3 Line No.: 1 Column: m***

Direct Assigned Facilities.

***Schedule Page: 328.3 Line No.: 2 Column: d***

Use of Facilities (S.A. 264) terminating July 2014.

***Schedule Page: 328.3 Line No.: 2 Column: m***

Direct Assigned Facilities. December 2007 Service. Invoicing Adjustment from contract start date of March 1999 to reflect actual cost of facility rather than estimate.

***Schedule Page: 328.3 Line No.: 3 Column: b***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.3 Line No.: 3 Column: c***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.3 Line No.: 3 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.: 4 Column: b***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.3 Line No.: 4 Column: c***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.3 Line No.: 4 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.: 4 Column: m***

December 2007 Service.

***Schedule Page: 328.3 Line No.: 5 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: 328.3 Line No.: 5 Column: m***

Regulation and Frequency Response. Penalty revenues covering imbalance charges per Schedules 4 and 9.

***Schedule Page: 328.3 Line No.: 6 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: 328.3 Line No.: 6 Column: m***

Unauthorized Use of Transmission Service. Regulation & Frequency Response. December 2007 Service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

***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.: 8 Column: b***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.3 Line No.: 8 Column: c***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.3 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: 328.3 Line No.: 9 Column: b***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.3 Line No.: 9 Column: c***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.3 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: 328.3 Line No.: 9 Column: m***

December 2007 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.

***Schedule Page: 328.3 Line No.: 11 Column: m***

December 2007 Service.

***Schedule Page: 328.3 Line No.: 12 Column: b***

Operation, maintenance or facility lease services with no receipt or delivery of energy.

***Schedule Page: 328.3 Line No.: 12 Column: c***

Operation, maintenance or facility lease services with no receipt or delivery of energy.

***Schedule Page: 328.3 Line No.: 12 Column: d***

Malin to Indian Springs Facilities lease (S.A. 607). Terminating December 31, 2017.

***Schedule Page: 328.3 Line No.: 12 Column: m***

Sole use of facilities charge.

***Schedule Page: 328.3 Line No.: 13 Column: d***

Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 170) terminating on May 31, 2009.

***Schedule Page: 328.3 Line No.: 14 Column: d***

Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 170) terminating on May 31, 2009.

***Schedule Page: 328.3 Line No.: 14 Column: m***

December 2007 Service.

***Schedule Page: 328.3 Line No.: 15 Column: b***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.3 Line No.: 15 Column: c***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.3 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: 328.3 Line No.: 16 Column: b***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.3 Line No.: 16 Column: c***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.3 Line No.: 16 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.: 17 Column: b***

Operation, maintenance or facility lease services with no receipt or delivery of energy.

***Schedule Page: 328.3 Line No.: 17 Column: c***

Operation, maintenance or facility lease services with no receipt or delivery of energy.

***Schedule Page: 328.3 Line No.: 17 Column: d***

Transmission Service Agreement (S.A. 123) for Network Services in PACE Terminating upon written notification.

***Schedule Page: 328.3 Line No.: 18 Column: b***

Operation, maintenance or facility lease services with no receipt or delivery of energy.

***Schedule Page: 328.3 Line No.: 18 Column: c***

Operation, maintenance or facility lease services with no receipt or delivery of energy.

***Schedule Page: 328.3 Line No.: 18 Column: d***

Transmission Service Agreement (S.A. 123) for Network Services in PACE Terminating upon written notification.

***Schedule Page: 328.3 Line No.: 18 Column: m***

December 2007 Service.

***Schedule Page: 328.3 Line No.: 19 Column: b***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.3 Line No.: 19 Column: c***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.3 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: 328.3 Line No.: 20 Column: b***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.3 Line No.: 20 Column: c***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.3 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: 328.3 Line No.: 21 Column: b***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.3 Line No.: 21 Column: c***

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

***Schedule Page: 328.3 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: 328.3 Line No.: 21 Column: m***

December 2007 Service.

***Schedule Page: 328.3 Line No.: 22 Column: d***

USBR contract #14-06-100-1152 dated March 26, 1957 superceded by Network Integration Transmission Service Agreement 506 effective September 1, 2008.

***Schedule Page: 328.3 Line No.: 22 Column: m***

Sole use of facilities charge.

***Schedule Page: 328.3 Line No.: 23 Column: d***

October 9, 1962 Crooked River Project wheeling agreement. Rate Schedule 67.

***Schedule Page: 328.3 Line No.: 24 Column: d***

March 26, 1957 Columbia Basin Project (Burbank Pump) wheeling agreement (S.A. 286). Terminating any time after April 1, 2040 with 4 years written notification.

***Schedule Page: 328.3 Line No.: 24 Column: m***

Sole use of facilities charge.

***Schedule Page: 328.3 Line No.: 25 Column: d***

March 26, 1957 Columbia Basin Project (Burbank Pump) wheeling agreement (S.A. 286). Terminating any time after April 1, 2040 with 4 years written notification.

***Schedule Page: 328.3 Line No.: 26 Column: d***

USBR contract #14-06-100-1152 dated March 26, 1957 superceded by Network Integration Transmission Service Agreement 506 effective September 1, 2008.

***Schedule Page: 328.3 Line No.: 26 Column: m***

December 2007 Service.

***Schedule Page: 328.3 Line No.: 27 Column: d***

Transmission Service and Operating Agreement for network service in PACE. Subject to termination upon mutual agreement.

***Schedule Page: 328.3 Line No.: 27 Column: m***

Charges for monitoring, scheduling, load following and spinning reserve. Distribution Service Charge.

***Schedule Page: 328.3 Line No.: 28 Column: d***

Transmission Service and Operating Agreement for network service in PACE. Subject to termination upon mutual agreement.

***Schedule Page: 328.3 Line No.: 28 Column: m***

Charges for monitoring, scheduling, load following and spinning reserve. Distribution Service Charge. December 2007 Service.

***Schedule Page: 328.3 Line No.: 29 Column: d***

Transmission Service and Operating Agreement for network service in PACE. Subject to termination upon mutual agreement.

***Schedule Page: 328.3 Line No.: 29 Column: m***

Charges for monitoring, scheduling, load following and spinning reserve.

***Schedule Page: 328.3 Line No.: 30 Column: d***

Transmission Service and Operating Agreement for network service in PACE. Subject to termination upon mutual agreement.

***Schedule Page: 328.3 Line No.: 30 Column: m***

Charges for monitoring, scheduling, load following and spinning reserve. December 2007 Service.

***Schedule Page: 328.3 Line No.: 31 Column: d***

Transmission Service Agreement (R.S. 591) terminating January 1, 2032.

***Schedule Page: 328.3 Line No.: 32 Column: d***

Transmission Service Agreement (R.S. 591) terminating January 1, 2032.

***Schedule Page: 328.3 Line No.: 32 Column: m***

December 2007 Service.

***Schedule Page: 328.3 Line No.: 33 Column: d***

March 26, 1957 Columbia Basin Project (Burbank Pump) wheeling agreement (S.A. 286). Terminating any time after April 1, 2040 with 4 years written notification.

***Schedule Page: 328.3 Line No.: 34 Column: d***

March 26, 1957 Columbia Basin Project (Burbank Pump) wheeling agreement (S.A. 286). Terminating any time after April 1, 2040 with 4 years written notification.

***Schedule Page: 328.3 Line No.: 34 Column: m***

December 2007 Service.

***Schedule Page: 328.4 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: 328.4 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: 328.4 Line No.: 3 Column: d***

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

***Schedule Page: 328.4 Line No.: 3 Column: m***

December 2007 Service.

***Schedule Page: 328.4 Line No.: 4 Column: d***

Evergreen Network Transmission Service under the Open Access Transmission Tariff (S.A. 175).

***Schedule Page: 328.4 Line No.: 4 Column: m***

Distribution Service Charge. Primary Delivery Service.

***Schedule Page: 328.4 Line No.: 5 Column: d***

Evergreen Network Transmission Service under the Open Access Transmission Tariff (S.A. 175).

***Schedule Page: 328.4 Line No.: 5 Column: m***

Distribution Service Charge. Primary Delivery Service. December 2007 Service.

***Schedule Page: 328.4 Line No.: 6 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 | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | TRANSFER OF ENERGY Magawatt-hours Received (c) | TRANSFER OF ENERGY Magawatt-hours Delivered (d) | EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e) | Energy Charges ($) (f) | Other Charges ($) (g) | Total Cost of Transmission ($) (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | Arizona Public Service | AD | 124 | 124 | 10,226 | | 6,368 | 16,594 |
| 2 | Arizona Public Service | LFP | 198,712 | 198,712 | 973,470 | | | 973,470 |
| 3 | Arizona Public Service | NF | 17,717 | 17,717 | 55,243 | | | 55,243 |
| 4 | Arizona Public Service | OS | 57 | 57 | 38,602 | | 26,826 | 65,428 |
| 5 | Arizona Public Service | SFP | 42,909 | 42,909 | 154,139 | | | 154,139 |
| 6 | Ashland, City of | FNS | 1,874 | 1,874 | | 18,351 | | 18,351 |
| 7 | Avista Corp. | FNS | 56,568 | 58,790 | 261,516 | | | 261,516 |
| 8 | Avista Corp. | NF | 27,614 | 27,614 | 91,304 | | | 91,304 |
| 9 | Avista Corp. | SFP | 4,272 | 4,272 | 11,499 | | | 11,499 |
| 10 | Big Horn Rural Electric | OS | | | | | 50,393 | 50,393 |
| 11 | Bonneville Power Adm. | AD | -3,054 | -3,054 | 344,409 | -14,734 | -103,957 | 225,718 |
| 12 | Bonneville Power Adm. | FNS | | | 523,904 | | 31,212 | 555,116 |
| 13 | Bonneville Power Adm. | LFP | 4,522,031 | 4,522,031 | 34,284,187 | | 396,780 | 34,680,967 |
| 14 | Bonneville Power Adm. | NF | | | 184,233 | | | 184,233 |
| 15 | Bonneville Power Adm. | OS | 5,899,423 | 6,158,553 | 35,496,376 | 55,194 | 2,525,606 | 38,077,176 |
| 16 | Bonneville Power Adm. | SFP | 35,702 | 35,702 | 97,158 | 45,507 | | 142,665 |
| | TOTAL | | 15,323,508 | 15,643,840 | 96,316,669 | 1,957,462 | 22,893,052 | 121,167,183 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## 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 | | | |
|---|---|---|---|---|---|---|---|---|
| | | | Magawatt-hours Received (c) | Magawatt-hours Delivered (d) | Demand Charges ($) (e) | Energy Charges ($) (f) | Other Charges ($) (g) | Total Cost of Transmission ($) (h) |
| 1 | CA. Ind. Sys. Operator | AD | | | | -2,458 | 529,018 | 526,560 |
| 2 | CA. Ind. Sys. Operator | OS | | | | | 10,953,089 | 10,953,089 |
| 3 | CA. Ind. Sys. Operator | SFP | 471,830 | 471,830 | | 1,736,385 | | 1,736,385 |
| 4 | Deseret Pwr Elect. Coop | AD | 4 | 4 | 30 | | | 30 |
| 5 | Deseret Pwr Elect. Coop | NF | 5 | 5 | 37 | | | 37 |
| 6 | Deseret Pwr Elect. Coop | SFP | 191,801 | 191,801 | 1,904,220 | | | 1,904,220 |
| 7 | El Paso Elect. Co. | NF | 975 | 975 | 1,124 | | | 1,124 |
| 8 | El Paso Elect. Co. | SFP | 30,818 | 30,818 | 51,337 | | | 51,337 |
| 9 | Flathead Elect. Coop. | AD | | | | | -1,392 | -1,392 |
| 10 | Flathead Elect. Coop. | OS | | | | | 66,719 | 66,719 |
| 11 | Flowell Electric Assoc. | AD | 25 | 25 | 42 | | | 42 |
| 12 | Flowell Electric Assoc. | LFP | 169 | 169 | 289 | | | 289 |
| 13 | Hermiston Gen Co., L.P. | OS | | | | | 170,064 | 170,064 |
| 14 | Idaho Power Company | AD | 29,406 | 29,406 | -39,293 | 82,166 | -2,973,156 | -2,930,283 |
| 15 | Idaho Power Company | FNS | | | 7,901 | | | 7,901 |
| 16 | Idaho Power Company | NF | 706,252 | 752,011 | 2,165,435 | 8,006 | | 2,173,441 |
| | TOTAL | | 15,323,508 | 15,643,840 | 96,316,669 | 1,957,462 | 22,893,052 | 121,167,183 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## 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 | | | |
|---|---|---|---|---|---|---|---|---|
| | | | Magawatt-hours Received (c) | Magawatt-hours Delivered (d) | Demand Charges ($) (e) | Energy Charges ($) (f) | Other Charges ($) (g) | Total Cost of Transmission ($) (h) |
| 1 | Idaho Power Company | OS | | | | | 8,917,609 | 8,917,609 |
| 2 | Idaho Power Company | SFP | 391,634 | 391,634 | 952,990 | | | 952,990 |
| 3 | Los Ang. Dept Water/Pwr | NF | 464 | 464 | 5,076 | | | 5,076 |
| 4 | Los Ang. Dept Water/Pwr | OS | | | | | 381 | 381 |
| 5 | MAPPCOR | OS | | | | | -1,026 | -1,026 |
| 6 | Moon Lake Elect. Assoc. | AD | | | | | -551 | -551 |
| 7 | Moon Lake Elect. Assoc. | FNS | | | | | 124,726 | 124,726 |
| 8 | Morgan City | AD | 18 | 18 | | 190 | | 190 |
| 9 | Navajo Tribal Util Auth | OS | | | | | 1,481 | 1,481 |
| 10 | Nevada Power Company | NF | 21,541 | 21,541 | 64,454 | | | 64,454 |
| 11 | Nevada Power Company | OS | | | | | 767,081 | 767,081 |
| 12 | Nevada Power Company | SFP | 846,838 | 846,838 | 3,922,152 | | | 3,922,152 |
| 13 | NorthWestern Energy | AD | | | -60,459 | | | -60,459 |
| 14 | NorthWestern Energy | NF | 30,360 | 31,191 | 134,910 | | | 134,910 |
| 15 | NorthWestern Energy | OS | | | | | 826,027 | 826,027 |
| 16 | NorthWestern Energy | SFP | 10,394 | 10,394 | 45,145 | | | 45,145 |
| | TOTAL | | 15,323,508 | 15,643,840 | 96,316,669 | 1,957,462 | 22,893,052 | 121,167,183 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | TRANSFER OF ENERGY: Magawatt-hours Received (c) | TRANSFER OF ENERGY: Magawatt-hours Delivered (d) | EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e) | Energy Charges ($) (f) | Other Charges ($) (g) | Total Cost of Transmission ($) (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | Platte River Power | AD | -1,461 | -1,461 | | | 118 | 118 |
| 2 | Platte River Power | OS | | | | | 12,115 | 12,115 |
| 3 | Platte River Power | SFP | 191,080 | 191,080 | 966,000 | | | 966,000 |
| 4 | Portland Gen. Electric | NF | 234 | 234 | 270 | | | 270 |
| 5 | Portland Gen. Electric | OS | 779,018 | 780,185 | | | 143,430 | 143,430 |
| 6 | Public Service Co of CO | LFP | 111,514 | 117,122 | 866,841 | | | 866,841 |
| 7 | Public Service Co of NM | OS | | | | | 21,349 | 21,349 |
| 8 | Public Service Co of NM | SFP | 115,558 | 115,558 | 603,783 | | | 603,783 |
| 9 | SUEZ Energy Mkt NA | SFP | | | 3,150,700 | | | 3,150,700 |
| 10 | Salt River Project | NF | 3,221 | 3,221 | 7,485 | | | 7,485 |
| 11 | Seattle City Light | NF | 150 | 150 | 450 | | | 450 |
| 12 | Sierra Pacific Power Co | NF | 16,083 | 16,083 | 96,189 | | | 96,189 |
| 13 | Sierra Pacific Power Co | OS | | | | | 15,358 | 15,358 |
| 14 | Suprise Valley Electr. | OS | | | | | 9,174 | 9,174 |
| 15 | Tri-State Gen & Transm | AD | -761 | -761 | 1,344 | | 471 | 1,815 |
| 16 | Tri-State Gen & Transm | LFP | 111,832 | 117,447 | 866,841 | | | 866,841 |
| | TOTAL | | 15,323,508 | 15,643,840 | 96,316,669 | 1,957,462 | 22,893,052 | 121,167,183 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | TRANSFER OF ENERGY: Magawatt-hours Received (c) | TRANSFER OF ENERGY: Magawatt-hours Delivered (d) | EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e) | Energy Charges ($) (f) | Other Charges ($) (g) | Total Cost of Transmission ($) (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | Tri-State Gen & Transm | NF | 18,637 | 18,637 | 50,956 | | | 50,956 |
| 2 | Tri-State Gen & Transm | OS | | | | | 17,760 | 17,760 |
| 3 | Tucson Electric Power | NF | 25 | 25 | 163 | | | 163 |
| 4 | Tucson Electric Power | OS | | | | | 15 | 15 |
| 5 | Utah Assoc Muni Pwr Sys | AD | | | 8,050 | | -6,657 | 1,393 |
| 6 | Utah Assoc Muni Pwr Sys | SFP | 258,147 | 258,147 | 1,293,600 | | 12,886 | 1,306,486 |
| 7 | Western Area Power Adm. | AD | | | -374 | | 247 | -127 |
| 8 | Western Area Power Adm. | FNS | | | 3,735,018 | | | 3,735,018 |
| 9 | Western Area Power Adm. | LFP | 178,530 | 178,530 | 2,965,000 | | | 2,965,000 |
| 10 | Western Area Power Adm. | NF | 5,068 | 5,068 | 22,386 | | | 22,386 |
| 11 | Western Area Power Adm. | OS | | | | 28,855 | 349,640 | 378,495 |
| 12 | Western Area Power Adm. | SFP | 150 | 150 | 311 | | 7,000 | 7,311 |
| 13 | Accrual True-up | | | | | | -3,152 | -3,152 |
| 14 | | | | | | | | |
| 15 | | | | | | | | |
| 16 | | | | | | | | |
| | TOTAL | | 15,323,508 | 15,643,840 | 96,316,669 | 1,957,462 | 22,893,052 | 121,167,183 |

***Schedule Page: 332 Line No.: 1 Column: b***

Settlement Adjustment

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

Ancillary Services and Use of Facilities

***Schedule Page: 332 Line No.: 2 Column: b***

Arizona Public Service Co. - Contract Termination Dates: May 1, 2013, August 31, 2013, January 11, 2041 and May 31, 2047

***Schedule Page: 332 Line No.: 4 Column: g***

Ancillary Services and Use of Facilities

***Schedule Page: 332 Line No.: 10 Column: g***

Use of Facilities

***Schedule Page: 332 Line No.: 11 Column: b***

Settlement Adjustment

***Schedule Page: 332 Line No.: 11 Column: g***

Ancillary Services and Use of Facilities

***Schedule Page: 332 Line No.: 12 Column: g***

Use of Facilities

***Schedule Page: 332 Line No.: 13 Column: b***

Bonneville Power Administration - Contract Termination Dates: July 1, 2009, October 1, 2009, January 1, 2010, January 1, 2011, July 1, 2011, September 1, 2011, December 1, 2011, April 1, 2012, July 1, 2012, November 1, 2012, July 1, 2013, September 1, 2013, October 1, 2013, December 1, 2013, January 1, 2014, October 1, 2027, November 1, 2033 and evergreen

***Schedule Page: 332 Line No.: 13 Column: g***

Ancillary Services

***Schedule Page: 332 Line No.: 15 Column: g***

Ancillary Services and Use of Facilities

***Schedule Page: 332.1 Line No.: 1 Column: b***

Settlement Adjustment

***Schedule Page: 332.1 Line No.: 1 Column: g***

Ancillary Services

***Schedule Page: 332.1 Line No.: 2 Column: g***

Ancillary Services

***Schedule Page: 332.1 Line No.: 4 Column: b***

Settlement Adjustment

***Schedule Page: 332.1 Line No.: 9 Column: b***

Settlement Adjustment

***Schedule Page: 332.1 Line No.: 9 Column: g***

Use of Facilities

***Schedule Page: 332.1 Line No.: 10 Column: g***

Use of Facilities

***Schedule Page: 332.1 Line No.: 11 Column: b***

Settlement Adjustment

***Schedule Page: 332.1 Line No.: 12 Column: b***

Flowell Electric Association - Contract Termination Date: One year written notice

***Schedule Page: 332.1 Line No.: 13 Column: g***

Use of Facilities

***Schedule Page: 332.1 Line No.: 14 Column: b***

Settlement Adjustment

***Schedule Page: 332.1 Line No.: 14 Column: g***

Ancillary Services and Respondent's portion of specified costs of certain facilities

***Schedule Page: 332.2 Line No.: 1 Column: g***

Ancillary Services, Use of Facilities and Respondent's portion of specified costs of certain facilities

***Schedule Page: 332.2 Line No.: 4 Column: g***

Ancillary Services

***Schedule Page: 332.2 Line No.: 5 Column: g***

Patronage refund

***Schedule Page: 332.2 Line No.: 6 Column: b***

Settlement Adjustment

***Schedule Page: 332.2 Line No.: 6 Column: g***

Use of Facilities

***Schedule Page: 332.2 Line No.: 7 Column: g***

Use of Facilities

***Schedule Page: 332.2 Line No.: 8 Column: b***

Settlement Adjustment

***Schedule Page: 332.2 Line No.: 9 Column: g***

Use of Facilities

***Schedule Page: 332.2 Line No.: 11 Column: g***

Ancillary Services

***Schedule Page: 332.2 Line No.: 13 Column: b***

Settlement Adjustment

***Schedule Page: 332.2 Line No.: 15 Column: g***

Ancillary Services, Use of Facilities and Respondent's portion of specified costs of certain facilities

***Schedule Page: 332.3 Line No.: 1 Column: b***

Settlement Adjustment

***Schedule Page: 332.3 Line No.: 1 Column: g***

Ancillary Services

***Schedule Page: 332.3 Line No.: 2 Column: g***

Ancillary Services

***Schedule Page: 332.3 Line No.: 5 Column: g***

Use of Facilities and Respondent's portion of specified costs of certain facilities

***Schedule Page: 332.3 Line No.: 6 Column: b***

Public Service Company of Colorado - Contract Termination Date: The date that all generating plants comprising PacifiCorp resources have been retired from service or interests transferred

***Schedule Page: 332.3 Line No.: 7 Column: g***

Ancillary Services

***Schedule Page: 332.3 Line No.: 13 Column: g***

Ancillary Services

***Schedule Page: 332.3 Line No.: 14 Column: g***

Use of Facilities

***Schedule Page: 332.3 Line No.: 15 Column: b***

Settlement Adjustment

***Schedule Page: 332.3 Line No.: 15 Column: g***

Ancillary Services

***Schedule Page: 332.3 Line No.: 16 Column: b***

Tri-State Generation & Transmission - Contract Termination Date: The date that all generating plants comprising PacifiCorp resources have been retired from service or interests transferred

***Schedule Page: 332.4 Line No.: 2 Column: g***

Ancillary Services

***Schedule Page: 332.4 Line No.: 4 Column: g***

Ancillary Services

***Schedule Page: 332.4 Line No.: 5 Column: b***

Settlement Adjustment

***Schedule Page: 332.4 Line No.: 5 Column: g***

Ancillary Services

***Schedule Page: 332.4 Line No.: 6 Column: g***

Ancillary Services

***Schedule Page: 332.4 Line No.: 7 Column: b***

Settlement Adjustment

***Schedule Page: 332.4 Line No.: 7 Column: g***

Ancillary Services

***Schedule Page: 332.4 Line No.: 9 Column: b***

Western Area Power Administration - Contract Termination Date: May 31, 2022

***Schedule Page: 332.4 Line No.: 11 Column: g***

Ancillary Services and Use of Facilities

***Schedule Page: 332.4 Line No.: 12 Column: g***

Reservation Fee

***Schedule Page: 332.4 Line No.: 13 Column: g***

Represents the difference between actual wheeling expenses for the period as reflected on the individual line items within this schedule, and the accruals charged to account 565 during the period.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

| Line No. | Description (a) | Amount (b) |
|---|---|---|
| 1 | Industry Association Dues | 645,728 |
| 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 and Economic Development: | |
| 8 | Economic Development Corporation of Utah | 124,000 |
| 9 | Linn-Benton Community College | 10,000 |
| 10 | Newspaper Agency Group | 10,000 |
| 11 | Oregon Cascades West Council of Governments | 10,000 |
| 12 | Oregon Economic Development Association | 10,000 |
| 13 | Port of Columbia | 5,000 |
| 14 | South Coast Development Council | 7,500 |
| 15 | Thermopolis-Hot Springs Cty. Economic Development Co | 5,000 |
| 16 | Utah Center for Rural Life | 8,000 |
| 17 | Utah Sports Commission | 57,072 |
| 18 | Wallowa County Chamber of Commerce | 5,000 |
| 19 | Wyoming Business Council | 5,380 |
| 20 | Other | 22,350 |
| 21 | | |
| 22 | Corporate Memberships and Subscriptions: | |
| 23 | Association of Regional Economic Partners, Inc. | 5,500 |
| 24 | Consortium for Energy Efficiency | 13,120 |
| 25 | Economic Development for Central Oregon | 7,500 |
| 26 | E Source Companies LLC | 13,220 |
| 27 | Greenlight Greater Portland | 25,000 |
| 28 | Idaho Mining Association | 6,000 |
| 29 | Intermountain Electrical Association | 9,000 |
| 30 | Laramie Economic Development Corporation | 5,000 |
| 31 | Northern Tier Transmission Group | 329,757 |
| 32 | Northwest Power and Conservation | 15,000 |
| 33 | Oregon Business Association | 11,000 |
| 34 | Oregon Business Council | 30,059 |
| 35 | Oregon Environmental Council | 5,000 |
| 36 | Oregon State University | 15,000 |
| 37 | Pacific Northwest Utilties Conference Committee | 50,302 |
| 38 | Portland Business Alliance | 39,250 |
| 39 | Portland Oregon Sports Authority | 5,000 |
| 40 | Redmond Economic Development | 5,000 |
| 41 | Rocky Mountain Electrical League | 18,000 |
| 42 | Salt Lake Area Chamber of Commerce | 30,555 |
| 43 | UCA Users Group | 5,000 |
| 44 | Utah Foundation | 22,500 |
| 45 | Utah Hispanic Chamber of Commerce | 5,000 |
| 46 | TOTAL | 18,540,495 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

| Line No. | Description (a) | Amount (b) |
|---|---|---|
| 6 | Utah Manufacturers Association | 6,000 |
| 7 | Utah Mining Association | 22,915 |
| 8 | Utah Taxpayers Association | 20,000 |
| 9 | West Association | 28,511 |
| 10 | Western Electricity Coordinating Council | 2,885,614 |
| 11 | Western Energy Institute | 40,000 |
| 12 | Yakima County Development | 5,000 |
| 13 | Other | 127,377 |
| 14 | | |
| 15 | Directors Fees - Regional Advisory Boards | -79,365 |
| 16 | | |
| 17 | Regulatory Asset Amortization: | |
| 18 | Glenrock Mine Stipulation-UT (Excluding Reclamation) | 149,625 |
| 19 | Glenrock Mine 1998 Case-UT (Excluding Reclamation) | 1,152,774 |
| 20 | Transition Plan | 3,892,299 |
| 21 | | |
| 22 | General: | |
| 23 | MEHC Cross Charge | 8,679,610 |
| 24 | Other | 14,342 |
| 25 | | |
| 26 | | |
| 27 | | |
| 28 | | |
| 29 | | |
| 30 | | |
| 31 | | |
| 32 | | |
| 33 | | |
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| 38 | | |
| 39 | | |
| 40 | | |
| 41 | | |
| 42 | | |
| 43 | | |
| 44 | | |
| 45 | | |
| 46 | TOTAL | 18,540,495 |

***Schedule Page: 335.1 Line No.: 15 Column: b***

The ($79,365) primarily represents unrealized losses for compensation defined pursuant to PacifiCorp's Deferred Compensation Plan for Regional Advisory Board members.

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(Next Page is 336)

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

### A. Summary of Depreciation and Amortization Charges

| Line No. | Functional Classification (a) | Depreciation Expense (Account 403) (b) | Depreciation Expense for Asset Retirement Costs (Account 403.1) (c) | Amortization of Limited Term Electric Plant (Account 404) (d) | Amortization of Other Electric Plant (Acc 405) (e) | Total (f) |
|---|---|---|---|---|---|---|
| 1 | Intangible Plant | | | 37,623,410 | | 37,623,410 |
| 2 | Steam Production Plant | 113,913,694 | | | | 113,913,694 |
| 3 | Nuclear Production Plant | | | | | |
| 4 | Hydraulic Production Plant-Conventional | 14,977,901 | | 41,345 | | 15,019,246 |
| 5 | Hydraulic Production Plant-Pumped Storage | | | | | |
| 6 | Other Production Plant | 53,966,013 | | 115,060 | | 54,081,073 |
| 7 | Transmission Plant | 58,235,144 | | | | 58,235,144 |
| 8 | Distribution Plant | 137,554,066 | | | | 137,554,066 |
| 9 | Regional Transmission and Market Operation | | | | | |
| 10 | General Plant | 37,989,569 | | 2,552,628 | | 40,542,197 |
| 11 | Common Plant-Electric | | | | | |
| 12 | TOTAL | 416,636,387 | | 40,332,443 | | 456,968,830 |

### B. Basis for Amortization Charges

The amortization of Limited-Term Electric Plant is based on straight-line amortization over the life of the asset.

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

| Line No. | Account No. (a) | Depreciable Plant Base (In Thousands) (b) | Estimated Avg. Service Life (c) | Net Salvage (Percent) (d) | Applied Depr. rates (Percent) (e) | Mortality Curve Type (f) | Average Remaining Life (g) |
|---|---|---|---|---|---|---|---|
| 12 | STEAM PRODUCTION | | | | | | |
| 13 | Hunter Plant | | | | | | |
| 14 | 310.20 UT | 246 | 60.99 | | 1.29 | | 36.00 |
| 15 | 311.00 UT | 205,230 | 59.03 | -5.97 | 1.51 | | 34.74 |
| 16 | 312.00 UT | 538,444 | 53.58 | -5.86 | 1.83 | | 32.94 |
| 17 | 314.00 UT | 152,756 | 45.86 | -7.47 | 2.26 | | 31.28 |
| 18 | 315.00 UT | 94,539 | 58.91 | -4.93 | 1.49 | | 35.05 |
| 19 | 316.00 UT | 3,641 | 50.05 | -4.79 | 1.94 | | 27.81 |
| 20 | | | | | | | |
| 21 | Jim Bridger Plant | | | | | | |
| 22 | 310.20 WY | 281 | 61.44 | | 1.25 | | 31.00 |
| 23 | 311.00 WY | 135,139 | 56.91 | -7.38 | 1.58 | | 30.06 |
| 24 | 312.00 WY | 604,505 | 48.62 | -7.04 | 2.02 | | 28.72 |
| 25 | 314.00 WY | 152,353 | 43.87 | -8.35 | 2.35 | | 27.46 |
| 26 | 315.00 WY | 54,660 | 59.17 | -6.57 | 1.49 | | 30.29 |
| 27 | 316.00 WY | 3,355 | 50.58 | -5.95 | 1.95 | | 24.79 |
| 28 | | | | | | | |
| 29 | Huntington Plant | | | | | | |
| 30 | 311.00 UT | 111,555 | 56.44 | -6.87 | 1.77 | | 29.12 |
| 31 | 312.00 UT | 376,958 | 40.67 | -6.67 | 2.63 | | 27.86 |
| 32 | 314.00 UT | 95,713 | 42.52 | -7.67 | 2.53 | | 26.69 |
| 33 | 315.00 UT | 41,743 | 54.66 | -6.03 | 1.81 | | 29.34 |
| 34 | 316.00 UT | 2,050 | 44.86 | -5.99 | 2.55 | | 24.16 |
| 35 | | | | | | | |
| 36 | Cholla Plant | | | | | | |
| 37 | 310.20 AZ | 1,169 | 34.00 | | 2.94 | | |
| 38 | 311.00 AZ | 55,364 | 57.24 | -6.03 | 1.57 | | 34.70 |
| 39 | 312.00 AZ | 318,192 | 55.30 | -5.07 | 1.50 | | 32.95 |
| 40 | 314.00 AZ | 63,438 | 53.18 | -6.97 | 1.71 | | 31.28 |
| 41 | 315.00 AZ | 64,912 | 59.39 | -4.37 | 1.29 | | 35.05 |
| 42 | 316.00 AZ | 3,163 | 51.05 | -4.44 | 1.68 | | 27.81 |
| 43 | | | | | | | |
| 44 | Dave Johnston Plant | | | | | | |
| 45 | 310.20 WY | 100 | 54.39 | | 1.77 | | 21.00 |
| 46 | 311.00 WY | 52,148 | 39.65 | -8.03 | 2.77 | | 20.57 |
| 47 | 312.00 WY | 302,668 | 39.37 | -7.85 | 2.88 | | 19.94 |
| 48 | 314.00 WY | 80,193 | 41.17 | -8.79 | 2.87 | | 19.34 |
| 49 | 315.00 WY | 16,786 | 48.20 | -7.42 | 2.24 | | 20.68 |
| 50 | 316.00 WY | 5,245 | 22.66 | -6.94 | 4.88 | | 18.04 |

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 | Wyodak Plant | | | | | | |
| 13 | 310.20 WY | 165 | 57.69 | | 1.42 | | 33.00 |
| 14 | 311.00 WY | 49,014 | 58.00 | -4.55 | 1.51 | | 31.94 |
| 15 | 312.00 WY | 206,727 | 51.51 | -4.21 | 1.79 | | 30.43 |
| 16 | 314.00 WY | 47,793 | 51.79 | -5.76 | 1.82 | | 29.02 |
| 17 | 315.00 WY | 19,631 | 59.96 | -3.62 | 1.43 | | 32.20 |
| 18 | 316.00 WY | 839 | 38.84 | -3.90 | 2.63 | | 26.03 |
| 19 | | | | | | | |
| 20 | Naughton Plant | | | | | | |
| 21 | 310.20 WY | 15 | 66.50 | | 1.39 | | 23.00 |
| 22 | 311.00 WY | 65,637 | 42.75 | -8.56 | 2.63 | | 22.47 |
| 23 | 312.00 WY | 246,960 | 39.85 | -8.01 | 2.82 | | 21.73 |
| 24 | 314.00 WY | 63,020 | 37.76 | -9.13 | 3.09 | | 21.01 |
| 25 | 315.00 WY | 20,609 | 45.48 | -7.63 | 2.37 | | 22.61 |
| 26 | 316.00 WY | 1,351 | 45.18 | -7.38 | 2.75 | | 19.46 |
| 27 | | | | | | | |
| 28 | Colstrip Plant | | | | | | |
| 29 | 311.00 MT | 57,363 | 59.49 | -4.43 | 1.38 | | 38.45 |
| 30 | 312.00 MT | 111,182 | 56.65 | -4.11 | 1.50 | | 36.26 |
| 31 | 314.00 MT | 32,120 | 50.57 | -6.19 | 1.86 | | 34.23 |
| 32 | 315.00 MT | 8,914 | 60.49 | -3.22 | 1.31 | | 38.83 |
| 33 | 316.00 MT | 2,203 | 49.09 | -3.76 | 1.85 | | 30.06 |
| 34 | | | | | | | |
| 35 | Craig Plant | | | | | | |
| 36 | 311.00 CO | 36,026 | 53.20 | -5.06 | 2.03 | | 27.24 |
| 37 | 312.00 CO | 91,079 | 44.30 | -4.74 | 2.45 | | 26.14 |
| 38 | 314.00 CO | 20,627 | 48.02 | -6.17 | 2.40 | | 25.10 |
| 39 | 315.00 CO | 16,537 | 54.21 | -4.25 | 1.96 | | 27.43 |
| 40 | 316.00 CO | 1,700 | 48.11 | -4.34 | 2.42 | | 22.88 |
| 41 | | | | | | | |
| 42 | Gadsby Plant | | | | | | |
| 43 | 311.00 UT | 15,055 | 40.24 | -13.60 | 1.28 | | 10.89 |
| 44 | 312.00 UT | 37,014 | 39.25 | -13.30 | 1.36 | | 10.72 |
| 45 | 314.00 UT | 14,517 | 42.80 | -13.54 | 1.07 | | 10.56 |
| 46 | 315.00 UT | 5,585 | 43.26 | -13.32 | 0.97 | | 10.92 |
| 47 | 316.00 UT | 553 | 26.42 | -12.41 | 3.08 | | 10.19 |
| 48 | | | | | | | |
| 49 | | | | | | | |
| 50 | | | | | | | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

| Line No. | Account No. (a) | Depreciable Plant Base (In Thousands) (b) | Estimated Avg. Service Life (c) | Net Salvage (Percent) (d) | Applied Depr. rates (Percent) (e) | Mortality Curve Type (f) | Average Remaining Life (g) |
|---|---|---|---|---|---|---|---|
| 12 | Carbon Plant | | | | | | |
| 13 | 311.00 UT | 14,152 | 40.18 | -8.12 | 2.55 | | 13.38 |
| 14 | 312.00 UT | 61,232 | 32.07 | -7.78 | 3.25 | | 13.44 |
| 15 | 314.00 UT | 25,572 | 35.21 | -8.28 | 3.00 | | 13.27 |
| 16 | 315.00 UT | 4,558 | 42.58 | -7.65 | 2.31 | | 13.86 |
| 17 | 316.00 UT | 235 | 40.25 | -7.21 | 2.58 | | 12.67 |
| 18 | | | | | | | |
| 19 | Blundell Plant | | | | | | |
| 20 | 310.20 UT | 40,982 | 38.12 | | 2.27 | | 27.00 |
| 21 | 311.00 UT | 7,405 | 46.46 | -2.25 | 1.69 | | 26.29 |
| 22 | 312.00 UT | 27,340 | 42.55 | -4.90 | 3.14 | | 25.06 |
| 23 | 314.00 UT | 30,801 | 42.07 | -3.70 | 2.12 | | 24.29 |
| 24 | 315.00 UT | 7,173 | 47.41 | -1.44 | 1.61 | | 26.47 |
| 25 | 316.00 UT | 1,020 | 42.94 | -2.31 | 1.96 | | 22.22 |
| 26 | | | | | | | |
| 27 | Camas Co-Gen Plant | | | | | | |
| 28 | 311.00 WA | 5,734 | 20.41 | -1.17 | 5.18 | | 9.91 |
| 29 | 312.00 WA | 5,798 | 20.28 | -1.15 | 5.25 | | 9.78 |
| 30 | 314.00 WA | 18,616 | 20.14 | -1.61 | 5.35 | | 9.64 |
| 31 | 315.00 WA | 4,302 | 20.26 | -0.93 | 5.20 | | 9.93 |
| 32 | | | | | | | |
| 33 | Hayden Plant | | | | | | |
| 34 | 311.00 CO | 6,002 | 50.19 | -5.51 | 1.94 | | 23.44 |
| 35 | 312.00 CO | 51,015 | 37.67 | -5.21 | 2.72 | | 22.63 |
| 36 | 314.00 CO | 6,762 | 46.89 | -6.28 | 2.18 | | 21.86 |
| 37 | 315.00 CO | 2,491 | 54.57 | -4.82 | 1.73 | | 23.58 |
| 38 | 316.00 CO | 1,106 | 42.92 | -4.75 | 2.46 | | 20.18 |
| 39 | | | | | | | |
| 40 | HYDRAULIC | | | | | | |
| 41 | PLANT | | | | | | |
| 42 | Swift | | | | | | |
| 43 | 330.20 WA | 6,277 | 88.23 | | 1.07 | | 40.00 |
| 44 | 330.50 WA | 97 | 86.50 | | 1.10 | | 40.00 |
| 45 | 331.00 WA | 6,739 | 68.37 | -1.63 | 1.47 | | 38.59 |
| 46 | 332.00 WA | 37,681 | 85.84 | -2.36 | 1.17 | | 38.67 |
| 47 | 333.00 WA | 11,505 | 71.26 | -4.32 | 1.48 | | 38.13 |
| 48 | 334.00 WA | 3,941 | 47.41 | -5.20 | 2.27 | | 36.02 |
| 49 | 335.00 WA | 417 | 78.26 | | 1.30 | | 35.20 |
| 50 | 336.00 WA | 395 | 57.95 | -2.18 | 1.76 | | 38.68 |

## 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 | Yale | | | | | | |
| 13 | 330.20 WA | 762 | 92.19 | | 1.04 | | 40.00 |
| 14 | 331.00 WA | 6,691 | 66.49 | -1.63 | 1.53 | | 38.61 |
| 15 | 332.00 WA | 26,569 | 87.60 | -2.36 | 1.13 | | 38.64 |
| 16 | 333.00 WA | 10,561 | 66.07 | -4.32 | 1.61 | | 38.19 |
| 17 | 334.00 WA | 3,662 | 50.53 | -5.20 | 2.15 | | 35.96 |
| 18 | 335.00 WA | 549 | 83.18 | | 1.24 | | 35.11 |
| 19 | 336.00 WA | 1,396 | 51.12 | -2.18 | 2.02 | | 38.73 |
| 20 | | | | | | | |
| 21 | Merwin | | | | | | |
| 22 | 330.20 WA | 301 | 111.67 | | 0.75 | | 40.00 |
| 23 | 330.50 WA | 212 | 113.50 | | 0.74 | | 40.00 |
| 24 | 331.00 WA | 28,584 | 55.01 | -1.63 | 1.81 | | 38.69 |
| 25 | 332.00 WA | 9,989 | 87.11 | -2.36 | 1.10 | | 38.63 |
| 26 | 333.00 WA | 7,514 | 74.02 | -4.32 | 1.38 | | 38.09 |
| 27 | 334.00 WA | 6,909 | 46.57 | -5.20 | 2.29 | | 36.22 |
| 28 | 335.00 WA | 134 | 68.33 | | 1.44 | | 35.39 |
| 29 | 336.00 WA | 2,230 | 57.70 | -2.18 | 1.74 | | 38.67 |
| 30 | | | | | | | |
| 31 | Klamath River | | | | | | |
| 32 | 330.20 CA/OR | 680 | 55.95 | | 1.81 | | 40.00 |
| 33 | 330.40 CA/OR | 253 | 76.16 | | 1.35 | | 40.00 |
| 34 | 331.00 CA/OR | 10,789 | 66.87 | -1.61 | 1.62 | | 38.00 |
| 35 | 332.00 CA/OR | 46,048 | 73.72 | -2.30 | 1.53 | | 37.66 |
| 36 | 333.00 CA/OR | 18,012 | 55.15 | -4.30 | 2.01 | | 38.06 |
| 37 | 334.00 CA/OR | 14,951 | 47.75 | -5.13 | 2.36 | | 35.57 |
| 38 | 335.00 CA/OR | 223 | 77.71 | | 1.45 | | 34.08 |
| 39 | 336.00 CA/OR | 2,486 | 61.98 | -2.13 | 1.76 | | 37.87 |
| 40 | | | | | | | |
| 41 | North Umpqua | | | | | | |
| 42 | 331.00 OR | 16,062 | 55.74 | -1.29 | 2.12 | | 31.11 |
| 43 | 332.00 OR | 79,666 | 66.10 | -2.14 | 1.92 | | 31.08 |
| 44 | 333.00 OR | 13,129 | 61.27 | -3.41 | 2.08 | | 30.81 |
| 45 | 334.00 OR | 8,377 | 46.99 | -4.15 | 2.58 | | 29.31 |
| 46 | 335.00 OR | 731 | 42.37 | | 2.60 | | 29.31 |
| 47 | 336.00 OR | 5,643 | 59.66 | -1.72 | 2.04 | | 31.10 |
| 48 | | | | | | | |
| 49 | | | | | | | |
| 50 | | | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

### C. Factors Used in Estimating Depreciation Charges

| Line No. | Account No. (a) | Depreciable Plant Base (In Thousands) (b) | Estimated Avg. Service Life (c) | Net Salvage (Percent) (d) | Applied Depr. rates (Percent) (e) | Mortality Curve Type (f) | Average Remaining Life (g) |
|---|---|---|---|---|---|---|---|
| 12 | Cutler | | | | | | |
| 13 | 330.30 UT | 5 | 97.24 | | 2.27 | | 18.00 |
| 14 | 330.40 UT | 91 | 73.81 | | 2.51 | | 18.00 |
| 15 | 331.00 UT | 3,809 | 37.07 | -0.67 | 3.57 | | 17.67 |
| 16 | 332.00 UT | 6,669 | 52.50 | -0.97 | 3.00 | | 17.68 |
| 17 | 333.00 UT | 11,670 | 77.93 | -1.79 | 2.59 | | 17.45 |
| 18 | 334.00 UT | 2,478 | 56.56 | -2.22 | 3.07 | | 16.79 |
| 19 | 335.00 UT | 13 | 40.22 | | 3.51 | | 16.89 |
| 20 | 336.00 UT | 572 | 40.47 | -0.90 | 3.42 | | 17.66 |
| 21 | | | | | | | |
| 22 | Prospect #1,2, and 4 | | | | | | |
| 23 | 330.20 OR | 4 | 65.95 | | 2.10 | | 31.00 |
| 24 | 330.40 OR | 3 | 100.50 | | 1.75 | | 31.00 |
| 25 | 331.00 OR | 2,993 | 52.67 | -1.24 | 2.46 | | 30.28 |
| 26 | 332.00 OR | 24,124 | 39.61 | -1.80 | 2.88 | | 30.34 |
| 27 | 333.00 OR | 2,708 | 60.23 | -3.30 | 2.45 | | 29.93 |
| 28 | 334.00 OR | 1,569 | 44.41 | -4.02 | 2.94 | | 28.55 |
| 29 | 335.00 OR | 22 | 32.00 | | 3.37 | | 26.87 |
| 30 | 336.00 OR | 259 | 59.83 | -1.66 | 2.34 | | 30.19 |
| 31 | | | | | | | |
| 32 | Pioneer | | | | | | |
| 33 | 330.20 UT | 9 | 133.42 | | 0.93 | | 24.00 |
| 34 | 330.30 UT | 111 | 133.50 | | 0.93 | | 24.00 |
| 35 | 331.00 UT | 426 | 57.22 | -0.94 | 1.94 | | 23.35 |
| 36 | 332.00 UT | 7,905 | 44.48 | -1.35 | 2.42 | | 23.62 |
| 37 | 333.00 UT | 2,135 | 37.88 | -2.49 | 2.84 | | 23.30 |
| 38 | 334.00 UT | 481 | 42.20 | -3.06 | 2.67 | | 22.21 |
| 39 | 335.00 UT | 10 | 43.50 | | 2.52 | | 22.15 |
| 40 | 336.00 UT | 12 | 51.88 | -1.25 | 2.12 | | 23.38 |
| 41 | | | | | | | |
| 42 | Lifton | | | | | | |
| 43 | 330.20 ID | 20 | 101.20 | | 1.91 | | 27.00 |
| 44 | 330.30 ID | 24 | 94.75 | | 1.96 | | 27.00 |
| 45 | 331.00 ID | 1,244 | 72.23 | -1.07 | 2.41 | | 26.34 |
| 46 | 332.00 ID | 7,737 | 56.19 | -1.55 | 2.71 | | 26.45 |
| 47 | 333.00 ID | 5,530 | 32.11 | -2.84 | 3.58 | | 26.25 |
| 48 | 334.00 ID | 265 | 51.20 | -3.48 | 3.23 | | 25.08 |
| 49 | 335.00 ID | 3 | 56.09 | | 2.62 | | 24.74 |
| 50 | 336.00 ID | 186 | 32.72 | -1.42 | 3.43 | | 26.43 |

## 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 | Ashton/St. Anthony | | | | | | |
| 13 | 330.20 ID | 29 | 40.50 | | 2.96 | | 21.00 |
| 14 | 331.00 ID | 1,219 | 43.26 | -0.80 | 2.91 | | 20.56 |
| 15 | 332.00 ID | 5,068 | 40.01 | -1.16 | 3.06 | | 20.63 |
| 16 | 333.00 ID | 2,449 | 39.19 | -2.14 | 3.16 | | 20.44 |
| 17 | 334.00 ID | 1,313 | 39.12 | -2.64 | 3.24 | | 19.90 |
| 18 | 335.00 ID | 8 | 47.70 | | 2.82 | | 19.51 |
| 19 | 336.00 ID | 1 | 109.90 | -1.07 | 1.79 | | 20.40 |
| 20 | | | | | | | |
| 21 | Bear River | | | | | | |
| 22 | 330.20 ID | 6 | 114.85 | | 1.40 | | 27.00 |
| 23 | 331.00 ID | 3,593 | 75.50 | -1.07 | 1.85 | | 26.24 |
| 24 | 332.00 ID | 19,892 | 69.33 | -1.55 | 1.96 | | 26.36 |
| 25 | 333.00 ID | 7,660 | 55.01 | -2.84 | 2.33 | | 26.10 |
| 26 | 334.00 ID | 3,260 | 49.96 | -3.48 | 2.58 | | 24.88 |
| 27 | 335.00 ID | 113 | 48.52 | | 2.50 | | 24.85 |
| 28 | 336.00 ID | 562 | 54.24 | -1.42 | 2.28 | | 26.32 |
| 29 | | | | | | | |
| 30 | Prospect #3 | | | | | | |
| 31 | 331.00 OR | 284 | 41.43 | -0.40 | 3.69 | | 11.88 |
| 32 | 332.00 OR | 4,101 | 33.71 | -0.58 | 4.17 | | 11.82 |
| 33 | 333.00 OR | 1,923 | 25.44 | -1.08 | 5.00 | | 11.76 |
| 34 | 334.00 OR | 475 | 26.21 | -1.35 | 5.04 | | 11.40 |
| 35 | 335.00 OR | 73 | 28.72 | | 4.69 | | 11.37 |
| 36 | 336.00 OR | 59 | 61.95 | -0.54 | 3.07 | | 11.73 |
| 37 | | | | | | | |
| 38 | Condit | | | | | | |
| 39 | 330.20 WA | | 77.50 | | 9.59 | | 2.00 |
| 40 | 330.40 WA | 3 | 97.50 | | 9.31 | | 2.00 |
| 41 | 331.00 WA | 1,013 | 35.92 | | 11.11 | | 2.00 |
| 42 | 332.00 WA | 4,310 | 40.79 | | 10.77 | | 2.00 |
| 43 | 333.00 WA | 1,196 | 27.30 | | 12.00 | | 2.00 |
| 44 | 334.00 WA | 197 | 29.32 | | 11.74 | | 2.00 |
| 45 | 335.00 WA | 4 | 16.50 | | 14.38 | | 2.00 |
| 46 | 336.00 WA | 60 | 56.09 | | 10.09 | | 2.00 |
| 47 | | | | | | | |
| 48 | | | | | | | |
| 49 | | | | | | | |
| 50 | | | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

### C. Factors Used in Estimating Depreciation Charges

| Line No. | Account No. (a) | Depreciable Plant Base (In Thousands) (b) | Estimated Avg. Service Life (c) | Net Salvage (Percent) (d) | Applied Depr. rates (Percent) (e) | Mortality Curve Type (f) | Average Remaining Life (g) |
|---|---|---|---|---|---|---|---|
| 12 | Big Fork | | | | | | |
| 13 | 331.00 MT | 589 | 74.76 | -1.93 | 0.29 | | 45.37 |
| 14 | 332.00 MT | 4,602 | 59.17 | -2.80 | 1.11 | | 45.29 |
| 15 | 333.00 MT | 1,445 | 57.64 | -5.11 | 1.22 | | 44.47 |
| 16 | 334.00 MT | 281 | 66.50 | -6.08 | 0.46 | | 37.43 |
| 17 | 336.00 MT | 212 | 124.20 | -2.57 | | | 46.55 |
| 18 | | | | | | | |
| 19 | Paris | | | | | | |
| 20 | 331.00 ID | 49 | 38.67 | -0.05 | 6.11 | | 3.98 |
| 21 | 332.00 ID | 96 | 62.19 | -0.07 | 5.19 | | 3.97 |
| 22 | 333.00 ID | 73 | 38.97 | -0.12 | 6.08 | | 3.97 |
| 23 | 334.00 ID | 105 | 28.85 | -0.15 | 6.98 | | 3.93 |
| 24 | 335.00 ID | 3 | 20.87 | | 8.25 | | 3.94 |
| 25 | | | | | | | |
| 26 | Wallowa Falls | | | | | | |
| 27 | 331.00 OR | 111 | 28.66 | -0.31 | 3.94 | | 9.80 |
| 28 | 332.00 OR | 900 | 28.07 | -0.45 | 4.00 | | 9.83 |
| 29 | 333.00 OR | 106 | 51.43 | -0.84 | 2.47 | | 9.58 |
| 30 | 334.00 OR | 1,391 | 19.65 | -1.05 | 5.62 | | 9.52 |
| 31 | 336.00 OR | 311 | 21.42 | -0.42 | 5.08 | | 9.84 |
| 32 | | | | | | | |
| 33 | Olmsted | | | | | | |
| 34 | 331.00 UT | 176 | 77.40 | -0.31 | 2.83 | | 9.72 |
| 35 | 334.00 UT | 29 | 17.31 | -1.05 | 6.79 | | 9.59 |
| 36 | 335.00 UT | 3 | 38.06 | | 4.13 | | 9.35 |
| 37 | 336.00 UT | 13 | 23.35 | -0.42 | 5.39 | | 9.85 |
| 38 | | | | | | | |
| 39 | Bend | | | | | | |
| 40 | 331.00 OR | 56 | 49.36 | -0.05 | | | 3.99 |
| 41 | 332.00 OR | 149 | 86.70 | -0.07 | | | 3.99 |
| 42 | 333.00 OR | 77 | 68.78 | -0.12 | | | 3.99 |
| 43 | 334.00 OR | 628 | 23.70 | -0.15 | | | 3.98 |
| 44 | 335.00 OR | 15 | 9.48 | | 7.21 | | 3.98 |
| 45 | 336.00 OR | | 74.49 | -0.06 | | | 3.99 |
| 46 | | | | | | | |
| 47 | | | | | | | |
| 48 | | | | | | | |
| 49 | | | | | | | |
| 50 | | | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

### C. Factors Used in Estimating Depreciation Charges

| Line No. | Account No. (a) | Depreciable Plant Base (In Thousands) (b) | Estimated Avg. Service Life (c) | Net Salvage (Percent) (d) | Applied Depr. rates (Percent) (e) | Mortality Curve Type (f) | Average Remaining Life (g) |
|---|---|---|---|---|---|---|---|
| 12 | Cline Falls | | | | | | |
| 13 | 331.00 OR | 117 | 29.56 | -0.18 | | | 6.96 |
| 14 | 332.00 OR | 120 | 44.61 | -0.26 | | | 6.96 |
| 15 | 333.00 OR | 47 | 66.57 | -0.48 | | | 6.94 |
| 16 | 334.00 OR | 54 | 29.16 | -0.56 | | | 6.86 |
| 17 | 336.00 OR | 1 | 70.46 | -0.24 | | | 6.96 |
| 18 | | | | | | | |
| 19 | Eagle Point | | | | | | |
| 20 | 330.20 OR | 12 | 68.50 | | 0.07 | | 19.00 |
| 21 | 331.00 OR | 128 | 44.73 | -0.72 | 1.17 | | 18.22 |
| 22 | 332.00 OR | 1,216 | 38.85 | -1.04 | 1.65 | | 18.49 |
| 23 | 333.00 OR | 252 | 51.20 | -1.91 | 0.81 | | 17.58 |
| 24 | 334.00 OR | 72 | 47.33 | -2.36 | 1.06 | | 16.18 |
| 25 | 336.00 OR | 112 | 29.15 | -0.96 | 2.82 | | 18.60 |
| 26 | | | | | | | |
| 27 | Weber | | | | | | |
| 28 | 331.00 UT | 367 | 44.46 | -0.49 | 3.29 | | 13.72 |
| 29 | 332.00 UT | 1,359 | 55.59 | -0.71 | 2.92 | | 13.73 |
| 30 | 333.00 UT | 874 | 36.15 | -1.32 | 3.77 | | 13.66 |
| 31 | 334.00 UT | 119 | 42.13 | -1.64 | 3.57 | | 13.12 |
| 32 | 335.00 UT | 22 | 35.38 | | 3.86 | | 13.17 |
| 33 | 336.00 UT | 40 | 26.01 | -0.66 | 4.60 | | 13.78 |
| 34 | | | | | | | |
| 35 | Santa Clara | | | | | | |
| 36 | 331.00 UT | 165 | 43.37 | -0.49 | 3.24 | | 13.71 |
| 37 | 332.00 UT | 972 | 45.36 | -0.71 | 3.15 | | 13.75 |
| 38 | 333.00 UT | 465 | 34.44 | -1.32 | 3.80 | | 13.66 |
| 39 | 334.00 UT | 629 | 27.36 | -1.64 | 4.54 | | 13.27 |
| 40 | 335.00 UT | 8 | 39.02 | | 3.55 | | 13.12 |
| 41 | 336.00 UT | 2 | 91.96 | -0.66 | 2.21 | | 13.61 |
| 42 | | | | | | | |
| 43 | Stairs | | | | | | |
| 44 | 331.00 UT | 181 | 50.83 | -0.72 | 2.38 | | 18.55 |
| 45 | 332.00 UT | 753 | 60.30 | -1.04 | 2.11 | | 18.57 |
| 46 | 333.00 UT | 513 | 37.64 | -1.91 | 3.07 | | 18.49 |
| 47 | 334.00 UT | 161 | 39.40 | -2.36 | 3.07 | | 17.73 |
| 48 | | | | | | | |
| 49 | | | | | | | |
| 50 | | | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

### C. Factors Used in Estimating Depreciation Charges

| Line No. | Account No. (a) | Depreciable Plant Base (In Thousands) (b) | Estimated Avg. Service Life (c) | Net Salvage (Percent) (d) | Applied Depr. rates (Percent) (e) | Mortality Curve Type (f) | Average Remaining Life (g) |
|---|---|---|---|---|---|---|---|
| 12 | Last Chance | | | | | | |
| 13 | 331.00 ID | 435 | 38.76 | -0.72 | 2.98 | | 18.61 |
| 14 | 332.00 ID | 1,035 | 38.87 | -1.04 | 2.99 | | 18.66 |
| 15 | 333.00 ID | 1,119 | 39.07 | -1.91 | 3.04 | | 18.49 |
| 16 | 334.00 ID | 246 | 28.98 | -2.36 | 3.92 | | 17.90 |
| 17 | 336.00 ID | 65 | 42.09 | -0.96 | 2.81 | | 18.59 |
| 18 | | | | | | | |
| 19 | Snake Creek | | | | | | |
| 20 | 331.00 UT | 70 | 44.94 | -0.49 | 2.78 | | 13.68 |
| 21 | 332.00 UT | 458 | 45.05 | -0.71 | 2.78 | | 13.72 |
| 22 | 333.00 UT | 264 | 36.67 | -1.32 | 3.30 | | 13.63 |
| 23 | 334.00 UT | 156 | 37.05 | -1.64 | 3.31 | | 13.48 |
| 24 | 335.00 UT | 2 | 33.62 | | 3.56 | | 13.12 |
| 25 | | | | | | | |
| 26 | Viva Naughton | | | | | | |
| 27 | 331.00 WY | 389 | 52.89 | -1.37 | 1.98 | | 33.01 |
| 28 | 332.00 WY | 104 | 52.72 | -2.29 | 2.01 | | 33.01 |
| 29 | 333.00 WY | 497 | 51.78 | -3.64 | 2.10 | | 32.71 |
| 30 | 334.00 WY | 159 | 51.26 | -4.42 | 2.20 | | 30.87 |
| 31 | 335.00 WY | 21 | 51.29 | | 2.05 | | 30.79 |
| 32 | | | | | | | |
| 33 | Granite | | | | | | |
| 34 | 331.00 UT | 463 | 61.39 | -0.94 | 2.16 | | 23.39 |
| 35 | 332.00 UT | 3,590 | 33.38 | -1.35 | 3.29 | | 23.58 |
| 36 | 333.00 UT | 721 | 47.35 | -2.49 | 2.60 | | 23.42 |
| 37 | 334.00 UT | 183 | 43.29 | -3.06 | 2.87 | | 22.27 |
| 38 | 335.00 UT | 1 | 58.17 | | 2.32 | | 22.07 |
| 39 | | | | | | | |
| 40 | Fountain Green | | | | | | |
| 41 | 331.00 UT | 36 | 50.52 | -0.05 | | | 4.06 |
| 42 | 332.00 UT | 319 | 20.28 | -0.07 | 1.30 | | 3.90 |
| 43 | 333.00 UT | 24 | 76.23 | -0.12 | | | 4.06 |
| 44 | 334.00 UT | 78 | 22.49 | -0.15 | 0.24 | | 1.91 |
| 45 | 335.00 UT | 2 | 23.17 | | 0.38 | | 2.67 |
| 46 | 336.00 UT | 1 | 78.54 | -0.06 | | | 4.04 |
| 47 | | | | | | | |
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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

### C. Factors Used in Estimating Depreciation Charges

| Line No. | Account No. (a) | Depreciable Plant Base (In Thousands) (b) | Estimated Avg. Service Life (c) | Net Salvage (Percent) (d) | Applied Depr. rates (Percent) (e) | Mortality Curve Type (f) | Average Remaining Life (g) |
|---|---|---|---|---|---|---|---|
| 12 | OTHER PRODUCTION | | | | | | |
| 13 | Hermiston Plant | | | | | | |
| 14 | 341.00 OR | 12,840 | 39.66 | -2.93 | 2.69 | | 29.95 |
| 15 | 342.00 OR | 25 | 39.63 | -2.76 | 2.72 | | 29.13 |
| 16 | 343.00 OR | 105,794 | 38.29 | -3.20 | 2.85 | | 29.10 |
| 17 | 344.00 OR | 40,074 | 39.68 | -2.90 | 2.70 | | 29.82 |
| 18 | 345.00 OR | 9,070 | 40.40 | -2.89 | 2.65 | | 29.91 |
| 19 | 346.00 OR | 497 | 40.46 | -2.90 | 2.65 | | 29.96 |
| 20 | | | | | | | |
| 21 | Little Mountain | | | | | | |
| 22 | 341.00 UT | 267 | 32.74 | -2.41 | 8.73 | | 3.00 |
| 23 | 342.00 UT | 121 | 39.39 | -2.41 | 8.23 | | 3.00 |
| 24 | 343.00 UT | 2,381 | 17.57 | -2.41 | 11.24 | | 3.00 |
| 25 | 344.00 UT | 2,363 | 8.42 | -2.41 | 16.88 | | 3.00 |
| 26 | 345.00 UT | 216 | 32.10 | -2.41 | 8.78 | | 3.00 |
| 27 | 346.00 UT | 12 | 39.50 | -2.41 | 8.22 | | 3.00 |
| 28 | | | | | | | |
| 29 | Currant Creek | | | | | | |
| 30 | 341.00 UT | 43,236 | 40.42 | -3.29 | 2.57 | | 38.92 |
| 31 | 342.00 UT | 3,298 | 39.02 | -3.05 | 2.66 | | 37.52 |
| 32 | 343.00 UT | 181,708 | 39.00 | -3.40 | 2.67 | | 37.50 |
| 33 | 344.00 UT | 75,924 | 40.21 | -3.23 | 2.58 | | 38.71 |
| 34 | 345.00 UT | 40,947 | 40.35 | -3.26 | 2.57 | | 38.85 |
| 35 | 346.00 UT | 2,969 | 40.42 | -3.27 | 2.57 | | 38.92 |
| 36 | | | | | | | |
| 37 | Gadsby Gas Peakers | | | | | | |
| 38 | 341.00 UT | 4,122 | 30.12 | -1.40 | 3.28 | | 25.97 |
| 39 | 342.00 UT | 2,284 | 29.84 | -1.33 | 3.31 | | 25.34 |
| 40 | 343.00 UT | 50,772 | 29.70 | -1.55 | 3.34 | | 25.34 |
| 41 | 344.00 UT | 15,873 | 30.37 | -1.38 | 3.25 | | 25.87 |
| 42 | 345.00 UT | 2,951 | 30.09 | -1.56 | 3.36 | | 25.88 |
| 43 | | | | | | | |
| 44 | Chehalis | | | | | | |
| 45 | 341.00 WA | 22,416 | 40.00 | -3.34 | 2.52 | | 34.75 |
| 46 | 342.00 WA | 1,597 | 40.00 | -3.34 | 2.52 | | 34.75 |
| 47 | 343.00 WA | 194,183 | 40.00 | -3.34 | 2.52 | | 34.75 |
| 48 | 344.00 WA | 82,234 | 40.00 | -3.34 | 2.52 | | 34.75 |
| 49 | 345.00 WA | 37,686 | 40.00 | -3.34 | 2.52 | | 34.75 |
| 50 | 346.00 WA | 3,217 | 40.00 | -3.34 | 2.52 | | 34.75 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

| Line No. | Account No.<br>(a) | Depreciable Plant Base (In Thousands)<br>(b) | Estimated Avg. Service Life<br>(c) | Net Salvage (Percent)<br>(d) | Applied Depr. rates (Percent)<br>(e) | Mortality Curve Type<br>(f) | Average Remaining Life<br>(g) |
|---|---|---|---|---|---|---|---|
| 12 | Eastside Mobile Gener. | | | | | | |
| 13 | 344.00 UT | 840 | 20.00 | | 5.00 | | |
| 14 | | | | | | | |
| 15 | SOLAR GENERATING | | | | | | |
| 16 | Utah Solar | | | | | | |
| 17 | 344.00 UT | 36 | 15.00 | | 8.84 | SQ | 3.00 |
| 18 | | | | | | | |
| 19 | Oregon Solar | | | | | | |
| 20 | 344.00 OR | 56 | 15.00 | | 5.73 | SQ | 4.00 |
| 21 | | | | | | | |
| 22 | Wyoming Solar | | | | | | |
| 23 | 344.00 WY | 61 | 15.00 | | 8.98 | SQ | 3.00 |
| 24 | | | | | | | |
| 25 | WIND GENERATION | | | | | | |
| 26 | Foote Creek | | | | | | |
| 27 | 341.00 WY | 110 | | | 3.84 | | |
| 28 | 343.00 WY | 32,339 | 26.09 | -0.95 | 3.92 | | 17.59 |
| 29 | 344.00 WY | 1,636 | 26.42 | -0.82 | 3.84 | | 17.92 |
| 30 | 345.00 WY | 2,891 | 26.46 | -0.82 | 3.84 | | 17.96 |
| 31 | | | | | | | |
| 32 | Leaning Juniper I | | | | | | |
| 33 | 341.00 OR | 4,911 | 25.47 | -0.52 | 3.96 | | 24.97 |
| 34 | 343.00 OR | 153,407 | 24.82 | -0.71 | 4.08 | | 24.32 |
| 35 | 344.00 OR | 5,140 | | | 3.96 | | |
| 36 | 345.00 OR | 8,399 | | | 3.96 | | |
| 37 | 346.00 OR | 80 | 25.47 | -0.52 | 3.96 | | 24.97 |
| 38 | | | | | | | |
| 39 | Marengo I & II | | | | | | |
| 40 | 341.00 WA | 10,189 | 24.87 | -1.00 | 4.06 | | 24.87 |
| 41 | 343.00 WA | 324,805 | 24.87 | -1.00 | 4.06 | | 24.87 |
| 42 | 344.00 WA | 9,221 | 24.87 | -1.00 | 4.06 | | 24.87 |
| 43 | 345.00 WA | 18,802 | 24.87 | -1.00 | 4.06 | | 24.87 |
| 44 | 346.00 WA | 337 | 24.87 | -1.00 | 4.06 | | 24.87 |
| 45 | | | | | | | |
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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

### C. Factors Used in Estimating Depreciation Charges

| Line No. | Account No. (a) | Depreciable Plant Base (In Thousands) (b) | Estimated Avg. Service Life (c) | Net Salvage (Percent) (d) | Applied Depr. rates (Percent) (e) | Mortality Curve Type (f) | Average Remaining Life (g) |
|---|---|---|---|---|---|---|---|
| 12 | Goodnoe Hills | | | | | | |
| 13 | 341.00 WA | 5,386 | 24.87 | -1.00 | 4.06 | | 24.87 |
| 14 | 343.00 WA | 165,154 | 24.87 | -1.00 | 4.06 | | 24.87 |
| 15 | 344.00 WA | 4,266 | 24.87 | -1.00 | 4.06 | | 24.87 |
| 16 | 345.00 WA | 8,774 | 24.87 | -1.00 | 4.06 | | 24.87 |
| 17 | 346.00 WA | 171 | 24.87 | -1.00 | 4.06 | | 24.87 |
| 18 | | | | | | | |
| 19 | Glenrock Wind | | | | | | |
| 20 | 341.00 WY | | 24.87 | -1.00 | 4.06 | | 24.87 |
| 21 | 342.00 WY | | 24.87 | -1.00 | 4.06 | | 24.87 |
| 22 | 343.00 WY | 199,426 | 24.87 | -1.00 | 4.06 | | 24.87 |
| 23 | 344.00 WY | | 24.87 | -1.00 | 4.06 | | 24.87 |
| 24 | 345.00 WY | | 24.87 | -1.00 | 4.06 | | 24.87 |
| 25 | 346.00 WY | | 24.87 | -1.00 | 4.06 | | 24.87 |
| 26 | | | | | | | |
| 27 | Seven Mile Hill Wind | | | | | | |
| 28 | 341.00 WY | | 24.87 | -1.00 | 4.06 | | 24.87 |
| 29 | 342.00 WY | | 24.87 | -1.00 | 4.06 | | 24.87 |
| 30 | 343.00 WY | 233,916 | 24.87 | -1.00 | 4.06 | | 24.87 |
| 31 | 344.00 WY | | 24.87 | -1.00 | 4.06 | | 24.87 |
| 32 | 345.00 WY | | 24.87 | -1.00 | 4.06 | | 24.87 |
| 33 | 346.00 WY | | 24.87 | -1.00 | 4.06 | | 24.87 |
| 34 | | | | | | | |
| 35 | TRANSMISSION PLANT | | | | | | |
| 36 | 350.20 | 63,548 | 70.00 | | 1.35 | R5 | 45.23 |
| 37 | 352.00 | 70,648 | 75.00 | -1.00 | 1.31 | S1 | 58.51 |
| 38 | 353.00 | 1,098,369 | 58.00 | -4.00 | 1.75 | R1.5 | 45.37 |
| 39 | 353.70 | 50,704 | 25.00 | | 3.78 | R2 | 15.75 |
| 40 | 354.00 | 430,317 | 65.00 | -7.00 | 1.56 | R5 | 42.12 |
| 41 | 355.00 | 537,891 | 52.00 | -42.00 | 2.63 | R2.5 | 37.15 |
| 42 | 356.00 | 695,175 | 60.00 | -42.00 | 2.25 | R4 | 39.52 |
| 43 | 356.20 | 20,701 | 65.00 | | 1.40 | S6 | 33.55 |
| 44 | 357.00 | 3,210 | 60.00 | | 1.65 | R2 | 52.87 |
| 45 | 358.00 | 7,490 | 60.00 | | 1.64 | R2 | 52.68 |
| 46 | 359.00 | 11,453 | 70.00 | | 1.39 | R5 | 54.19 |
| 47 | | | | | | | |
| 48 | | | | | | | |
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| 50 | | | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

### C. Factors Used in Estimating Depreciation Charges

| Line No. | Account No. (a) | Depreciable Plant Base (In Thousands) (b) | Estimated Avg. Service Life (c) | Net Salvage (Percent) (d) | Applied Depr. rates (Percent) (e) | Mortality Curve Type (f) | Average Remaining Life (g) |
|---|---|---|---|---|---|---|---|
| 12 | DISTRIBUTION PLANT | | | | | | |
| 13 | 360.20 OR | 3,432 | 53.00 | | 1.67 | R4 | 22.94 |
| 14 | 361.00 OR | 14,745 | 65.00 | -5.00 | 1.58 | R1.5 | 53.12 |
| 15 | 362.00 OR | 174,608 | 52.00 | -10.00 | 2.06 | R1 | 39.62 |
| 16 | 362.70 OR | 2,973 | 23.00 | | 3.99 | R2.5 | 11.80 |
| 17 | 364.00 OR | 300,229 | 49.00 | -100.00 | 3.95 | R2 | 35.84 |
| 18 | 365.00 OR | 219,470 | 58.00 | -80.00 | 3.01 | R1.5 | 43.32 |
| 19 | 366.00 OR | 79,438 | 60.00 | -60.00 | 2.61 | R2.5 | 47.80 |
| 20 | 367.00 OR | 144,272 | 58.00 | -45.00 | 2.44 | R2.5 | 45.87 |
| 21 | 368.00 OR | 364,484 | 40.00 | -20.00 | 2.89 | R1.5 | 27.79 |
| 22 | 369.10 OR | 67,041 | 65.00 | -25.00 | 1.88 | R2 | 50.93 |
| 23 | 369.20 OR | 138,607 | 55.00 | -20.00 | 2.14 | R4 | 44.61 |
| 24 | 370.00 OR | 60,038 | 26.00 | -2.00 | 3.64 | R2.5 | 14.13 |
| 25 | 371.00 OR | 2,432 | 25.00 | -40.00 | 4.80 | S1 | 9.44 |
| 26 | 373.00 OR | 21,350 | 40.00 | -26.00 | 3.06 | R1 | 29.77 |
| 27 | | | | | | | |
| 28 | DISTRIBUTION PLANT | | | | | | |
| 29 | 360.20 WA | 227 | 50.00 | | 1.88 | R4 | 22.03 |
| 30 | 361.00 WA | 2,239 | 60.00 | -5.00 | 1.73 | R1.5 | 47.63 |
| 31 | 362.00 WA | 45,643 | 53.00 | -10.00 | 2.04 | R1.5 | 39.87 |
| 32 | 362.70 WA | 827 | 22.00 | | 4.22 | R4 | 8.94 |
| 33 | 364.00 WA | 84,621 | 50.00 | -110.00 | 4.14 | R1.5 | 39.26 |
| 34 | 365.00 WA | 55,519 | 60.00 | -80.00 | 2.95 | R1.5 | 45.71 |
| 35 | 366.00 WA | 14,586 | 40.00 | -80.00 | 4.41 | R4 | 28.07 |
| 36 | 367.00 WA | 19,452 | 45.00 | -35.00 | 2.95 | R4 | 33.03 |
| 37 | 368.00 WA | 89,292 | 42.00 | -25.00 | 2.90 | R2.5 | 28.10 |
| 38 | 369.10 WA | 16,113 | 50.00 | -15.00 | 2.25 | R2.5 | 34.11 |
| 39 | 369.20 WA | 28,923 | 55.00 | -45.00 | 2.61 | R4 | 44.34 |
| 40 | 370.00 WA | 13,846 | 26.00 | -5.00 | 3.84 | R2.5 | 12.73 |
| 41 | 371.00 WA | 527 | 30.00 | -15.00 | 3.70 | L0 | 17.21 |
| 42 | 373.00 WA | 3,741 | 40.00 | -30.00 | 3.15 | R3 | 24.74 |
| 43 | | | | | | | |
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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

### C. Factors Used in Estimating Depreciation Charges

| Line No. | Account No. (a) | Depreciable Plant Base (In Thousands) (b) | Estimated Avg. Service Life (c) | Net Salvage (Percent) (d) | Applied Depr. rates (Percent) (e) | Mortality Curve Type (f) | Average Remaining Life (g) |
|---|---|---|---|---|---|---|---|
| 12 | DISTRIBUTION PLANT | | | | | | |
| 13 | 360.20 WY | 3,303 | 50.00 | | 1.79 | R4 | 27.00 |
| 14 | 361.00 WY | 7,096 | 55.00 | -7.00 | 1.86 | R2 | 40.24 |
| 15 | 362.00 WY | 103,968 | 50.00 | -12.00 | 2.12 | S1 | 34.94 |
| 16 | 362.70 WY | 2,101 | 20.00 | | 3.81 | R4 | 6.87 |
| 17 | 364.00 WY | 97,723 | 50.00 | -71.00 | 3.31 | R1 | 39.43 |
| 18 | 365.00 WY | 87,899 | 55.00 | -55.00 | 2.71 | R1 | 41.67 |
| 19 | 366.00 WY | 14,650 | 42.00 | -70.00 | 3.85 | R3 | 30.15 |
| 20 | 367.00 WY | 43,131 | 40.00 | -49.00 | 3.48 | R5 | 26.12 |
| 21 | 368.00 WY | 81,433 | 38.00 | -20.00 | 3.00 | R1 | 27.27 |
| 22 | 369.10 WY | 14,306 | 60.00 | -15.00 | 1.85 | R2 | 46.40 |
| 23 | 369.20 WY | 27,097 | 45.00 | -38.00 | 2.94 | S5 | 33.74 |
| 24 | 370.00 WY | 15,568 | 26.00 | -5.00 | 3.57 | R2.5 | 13.40 |
| 25 | 371.00 WY | 902 | 20.00 | -60.00 | 5.97 | S-.5 | 6.59 |
| 26 | 373.00 WY | 8,921 | 50.00 | -45.00 | 2.79 | R0.5 | 38.72 |
| 27 | | | | | | | |
| 28 | DISTRIBUTION PLANT | | | | | | |
| 29 | 360.20 CA | 914 | 55.00 | | 2.31 | R4 | 20.10 |
| 30 | 361.00 CA | 1,481 | 55.00 | -5.00 | 2.05 | R4 | 37.62 |
| 31 | 362.00 CA | 20,258 | 55.00 | -25.00 | 2.39 | R1 | 41.60 |
| 32 | 362.70 CA | 218 | 20.00 | | 7.06 | R5 | 5.47 |
| 33 | 364.00 CA | 48,222 | 50.00 | -125.00 | 4.72 | R1.5 | 37.94 |
| 34 | 365.00 CA | 31,785 | 65.00 | -95.00 | 3.12 | S-.5 | 51.70 |
| 35 | 366.00 CA | 14,918 | 50.00 | -60.00 | 3.42 | R5 | 34.58 |
| 36 | 367.00 CA | 16,394 | 45.00 | -135.00 | 5.65 | S6 | 29.50 |
| 37 | 368.00 CA | 44,506 | 50.00 | -45.00 | 3.15 | R5 | 32.34 |
| 38 | 369.10 CA | 7,922 | 55.00 | -120.00 | 4.15 | R1 | 44.37 |
| 39 | 369.20 CA | 13,631 | 60.00 | -100.00 | 3.45 | R4 | 48.69 |
| 40 | 370.00 CA | 3,939 | 26.00 | -4.00 | 4.60 | R2.5 | 13.24 |
| 41 | 371.00 CA | 271 | 25.00 | -95.00 | 8.78 | L0 | 13.85 |
| 42 | 373.00 CA | 660 | 35.00 | -70.00 | 5.72 | R3 | 16.36 |
| 43 | | | | | | | |
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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

### C. Factors Used in Estimating Depreciation Charges

| Line No. | Account No. (a) | Depreciable Plant Base (In Thousands) (b) | Estimated Avg. Service Life (c) | Net Salvage (Percent) (d) | Applied Depr. rates (Percent) (e) | Mortality Curve Type (f) | Average Remaining Life (g) |
|---|---|---|---|---|---|---|---|
| 12 | DISTRIBUTION PLANT | | | | | | |
| 13 | 360.20 UT | 6,517 | 50.00 | | 1.86 | R4 | 36.84 |
| 14 | 361.00 UT | 31,237 | 60.00 | | 1.61 | R2 | 50.90 |
| 15 | 362.00 UT | 343,011 | 45.00 | -5.00 | 2.25 | S-.5 | 38.25 |
| 16 | 362.70 UT | 11,768 | 25.00 | | 3.49 | R3 | 15.33 |
| 17 | 363.00 UT | 1,393 | 15.00 | | 6.25 | SQ | 11.50 |
| 18 | 363.70 UT | 65 | 15.00 | | 6.25 | SQ | 11.50 |
| 19 | 364.00 UT | 279,646 | 40.00 | -55.00 | 3.53 | S2 | 27.88 |
| 20 | 365.00 UT | 189,409 | 42.00 | -40.00 | 3.15 | R0.5 | 32.98 |
| 21 | 366.00 UT | 147,470 | 60.00 | -45.00 | 2.30 | R2 | 48.48 |
| 22 | 367.00 UT | 426,168 | 50.00 | -25.00 | 2.35 | R2 | 38.87 |
| 23 | 368.00 UT | 370,914 | 45.00 | | 2.11 | R0.5 | 36.26 |
| 24 | 369.00 UT | 194,727 | 55.00 | -5.00 | 1.83 | S5 | 45.28 |
| 25 | 370.00 UT | 80,052 | 26.00 | -4.00 | 3.25 | R2.5 | 13.53 |
| 26 | 371.00 UT | 4,517 | 25.00 | -70.00 | 6.10 | L0 | 16.53 |
| 27 | 372.00 UT | | 30.00 | | 2.45 | L0 | 13.00 |
| 28 | 373.00 UT | 26,226 | 25.00 | -20.00 | 4.34 | R0.5 | 16.93 |
| 29 | | | | | | | |
| 30 | DISTRIBUTION PLANT | | | | | | |
| 31 | 360.20 ID | 956 | 50.00 | | 1.70 | R4 | 36.84 |
| 32 | 361.00 ID | 1,495 | 60.00 | | 1.54 | R2 | 50.90 |
| 33 | 362.00 ID | 25,912 | 45.00 | -7.00 | 2.20 | S-.5 | 38.25 |
| 34 | 362.70 ID | 352 | 25.00 | | 2.93 | R3 | 15.33 |
| 35 | 364.00 ID | 57,409 | 40.00 | -67.00 | 3.41 | S2 | 27.88 |
| 36 | 365.00 ID | 33,200 | 42.00 | -35.00 | 2.84 | R0.5 | 32.98 |
| 37 | 366.00 ID | 7,137 | 60.00 | -45.00 | 2.17 | R2 | 48.48 |
| 38 | 367.00 ID | 23,194 | 50.00 | -15.00 | 2.02 | R2 | 38.87 |
| 39 | 368.00 ID | 63,512 | 45.00 | -10.00 | 2.20 | R0.5 | 36.26 |
| 40 | 369.00 ID | 26,576 | 55.00 | -15.00 | 1.90 | S5 | 45.28 |
| 41 | 370.00 ID | 13,900 | 26.00 | -3.00 | 3.22 | R2.5 | 15.23 |
| 42 | 371.00 ID | 165 | 25.00 | -45.00 | 4.58 | L0 | 16.41 |
| 43 | 372.00 ID | | 30.00 | | 1.49 | L0 | 13.00 |
| 44 | 373.00 ID | 598 | 25.00 | -50.00 | 4.79 | R0.5 | 16.93 |
| 45 | | | | | | | |
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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

### C. Factors Used in Estimating Depreciation Charges

| Line No. | Account No. (a) | Depreciable Plant Base (In Thousands) (b) | Estimated Avg. Service Life (c) | Net Salvage (Percent) (d) | Applied Depr. rates (Percent) (e) | Mortality Curve Type (f) | Average Remaining Life (g) |
|---|---|---|---|---|---|---|---|
| 12 | GENERAL PLANT-OR | | | | | | |
| 13 | 390.00 OR | 60,592 | 50.00 | -10.00 | 2.21 | R1.5 | 40.92 |
| 14 | 391.10 OR | 3,674 | 5.00 | | 20.42 | L2 | 2.81 |
| 15 | 392.10 OR | 9,659 | 12.00 | 10.00 | 7.63 | R3 | 7.20 |
| 16 | 392.50 OR | 9,658 | 18.00 | 10.00 | 5.05 | S2 | 12.86 |
| 17 | 392.90 OR | 2,820 | 35.00 | 15.00 | 2.45 | S1 | 25.44 |
| 18 | 396.30 OR | 5,217 | 9.00 | 15.00 | 9.71 | R4 | 4.30 |
| 19 | 396.70 OR | 23,814 | 15.00 | 20.00 | 5.39 | L1 | 10.61 |
| 20 | 397.00 OR | 88,627 | 25.00 | | 4.06 | R2 | 16.28 |
| 21 | | | | | | | |
| 22 | GENERAL PLANT-WA | | | | | | |
| 23 | 390.00 WA | 10,918 | 30.00 | -10.00 | 3.80 | R3 | 20.37 |
| 24 | 392.10 WA | 2,193 | 12.00 | 10.00 | 7.91 | R3 | 6.98 |
| 25 | 392.50 WA | 3,453 | 14.00 | 10.00 | 6.66 | R3 | 9.50 |
| 26 | 392.90 WA | 625 | 33.00 | 15.00 | 2.65 | S0.5 | 24.18 |
| 27 | 396.30 WA | 1,263 | 10.00 | 10.00 | 9.69 | R4 | 4.93 |
| 28 | 396.70 WA | 5,817 | 13.00 | 15.00 | 6.81 | L1.5 | 8.41 |
| 29 | 397.00 WA | 13,259 | 20.00 | | 5.24 | R2 | 12.16 |
| 30 | | | | | | | |
| 31 | GENERAL PLANT- | | | | | | |
| 32 | AZ,CO,MT,NM, ETC. | | | | | | |
| 33 | 390.00 | 384 | 40.00 | | 2.06 | R1 | 26.62 |
| 34 | 392.10 | 571 | 13.00 | | 6.42 | L0 | 8.81 |
| 35 | 392.50 | 234 | 16.00 | 15.00 | 2.96 | R1.5 | 7.03 |
| 36 | 392.90 | 39 | 25.00 | | 2.18 | R1.5 | 10.84 |
| 37 | 396.70 | 2,385 | 25.00 | 5.00 | 2.71 | R3 | 13.68 |
| 38 | 397.00 | 5,003 | 25.00 | -5.00 | 3.18 | R1.5 | 14.71 |
| 39 | | | | | | | |
| 40 | GENERAL PLANT-ID | | | | | | |
| 41 | 389.20 ID | 5 | 40.00 | | 2.01 | R1 | 20.57 |
| 42 | 390.00 ID | 10,525 | 40.00 | -5.00 | 2.12 | R1 | 29.69 |
| 43 | 392.10 ID | 2,478 | 11.00 | 10.00 | 6.66 | S4 | 5.81 |
| 44 | 392.50 ID | 2,818 | 15.00 | 15.00 | 5.22 | L2 | 10.90 |
| 45 | 392.90 ID | 859 | 33.00 | 10.00 | 2.50 | L2 | 23.66 |
| 46 | 396.30 ID | 1,510 | 7.00 | 10.00 | 9.15 | R3 | 2.93 |
| 47 | 396.70 ID | 6,526 | 18.00 | 25.00 | 3.87 | L0.5 | 13.43 |
| 48 | 397.00 ID | 13,688 | 25.00 | -5.00 | 3.79 | S-.5 | 17.03 |
| 49 | | | | | | | |
| 50 | | | | | | | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

### C. Factors Used in Estimating Depreciation Charges

| Line No. | Account No. (a) | Depreciable Plant Base (In Thousands) (b) | Estimated Avg. Service Life (c) | Net Salvage (Percent) (d) | Applied Depr. rates (Percent) (e) | Mortality Curve Type (f) | Average Remaining Life (g) |
|---|---|---|---|---|---|---|---|
| 12 | GENERAL PLANT-WY | | | | | | |
| 13 | 389.20 WY | 74 | 50.00 | | 2.01 | SQ | 48.63 |
| 14 | 390.00 WY | 6,123 | 40.00 | -15.00 | 3.03 | R3 | 26.52 |
| 15 | 392.10 WY | 5,069 | 13.00 | 10.00 | 7.34 | S1.5 | 8.26 |
| 16 | 392.50 WY | 5,004 | 14.00 | 10.00 | 6.80 | S2 | 9.04 |
| 17 | 392.90 WY | 2,708 | 30.00 | 5.00 | 3.37 | R4 | 18.71 |
| 18 | 396.30 WY | 2,362 | 9.00 | 15.00 | 10.37 | R4 | 4.67 |
| 19 | 396.70 WY | 25,793 | 15.00 | 25.00 | 5.19 | S-.5 | 10.97 |
| 20 | 397.00 WY | 31,900 | 20.00 | -2.00 | 5.40 | L2 | 12.80 |
| 21 | | | | | | | |
| 22 | GENERAL PLANT-CA | | | | | | |
| 23 | 390.00 CA | 1,480 | 50.00 | -20.00 | 2.38 | R3 | 33.57 |
| 24 | 392.10 CA | 789 | 10.00 | 20.00 | 7.89 | S3 | 5.79 |
| 25 | 392.50 CA | 824 | 15.00 | 15.00 | 5.63 | L2 | 10.99 |
| 26 | 392.90 CA | 340 | 35.00 | 5.00 | 2.69 | R4 | 22.82 |
| 27 | 396.30 CA | 875 | 8.00 | 15.00 | 10.34 | R4 | 3.27 |
| 28 | 396.70 CA | 2,492 | 15.00 | 15.00 | 5.60 | R2.5 | 9.31 |
| 29 | 397.00 CA | 4,469 | 25.00 | -5.00 | 4.15 | R2 | 15.47 |
| 30 | | | | | | | |
| 31 | GENERAL PLANT-UT | | | | | | |
| 32 | 389.20 UT | 35 | 40.00 | | 2.32 | R1 | 20.32 |
| 33 | 390.00 UT | 85,222 | 40.00 | 10.00 | 2.18 | R1 | 28.74 |
| 34 | 392.10 UT | 18,353 | 12.00 | 10.00 | 7.07 | R3 | 6.80 |
| 35 | 392.30 UT | 3,643 | 10.00 | 64.00 | 3.59 | SQ | 9.50 |
| 36 | 392.50 UT | 20,921 | 16.00 | 10.00 | 5.41 | L2 | 10.60 |
| 37 | 392.90 UT | 6,297 | 28.00 | 25.00 | 2.57 | S1 | 17.83 |
| 38 | 396.30 UT | 3,339 | 8.00 | 10.00 | 10.07 | R4 | 3.28 |
| 39 | 396.70 UT | 45,080 | 12.00 | 15.00 | 6.84 | L0.5 | 8.22 |
| 40 | 397.00 UT | 80,775 | 25.00 | -5.00 | 4.09 | R1 | 18.38 |
| 41 | | | | | | | |
| 42 | | | | | | | |
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| 50 | | | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

### C. Factors Used in Estimating Depreciation Charges

| Line No. | Account No. (a) | Depreciable Plant Base (In Thousands) (b) | Estimated Avg. Service Life (c) | Net Salvage (Percent) (d) | Applied Depr. rates (Percent) (e) | Mortality Curve Type (f) | Average Remaining Life (g) |
|---|---|---|---|---|---|---|---|
| 12 | GENERAL PLANT-ALL | | | | | | |
| 13 | STATES | | | | | | |
| 14 | 390.30 | 12,694 | 15.00 | | 6.67 | | |
| 15 | 391.00 | 26,661 | 20.00 | | 5.00 | | |
| 16 | 391.20 | 57,802 | 5.00 | | 20.00 | | |
| 17 | 391.30 | 906 | 8.00 | | 12.50 | | |
| 18 | 393.00 | 13,644 | 25.00 | | 4.00 | | |
| 19 | 394.00 | 62,698 | 24.00 | | 4.17 | | |
| 20 | 395.00 | 38,926 | 20.00 | | 5.00 | | |
| 21 | 397.20 | 4,164 | 11.00 | | 9.09 | | |
| 22 | 398.00 | 6,358 | 20.00 | | 5.00 | | |
| 23 | | | | | | | |
| 24 | MINING | | | | | | |
| 25 | 399.30 UT | 16,112 | 34.64 | -0.50 | 0.81 | FCST | 12.51 |
| 26 | 399.30 UT | 24,087 | 49.30 | -5.95 | 1.86 | FCST | 34.74 |
| 27 | 399.41 UT | 12,181 | 48.88 | -5.95 | 1.88 | FCST | 34.74 |
| 28 | 399.44 UT | 3,425 | 13.20 | | 7.44 | SQ | 12.70 |
| 29 | 399.45 UT | 115,577 | 12.00 | 5.00 | 4.62 | L2 | 6.26 |
| 30 | 399.51 UT | 1,134 | 14.00 | 5.00 | 4.49 | S3 | 8.02 |
| 31 | 399.52 UT | 4,991 | 18.00 | 5.00 | 3.08 | R5 | 9.39 |
| 32 | 399.60 UT | 2,117 | 13.00 | 1.00 | 4.97 | L1.5 | 7.36 |
| 33 | 399.61 UT | 616 | 8.00 | | 1.76 | R4 | 2.77 |
| 34 | 399.70 UT | 36,840 | 24.45 | | 2.54 | FCST | 12.51 |
| 35 | | | | | | | |
| 36 | | | | | | | |
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| 50 | | | | | | | |

***Schedule Page: 336 Line No.: 12 Column: b***

Vehicle depreciation is charged to functional accounts. During the year ended December 31, 2008, vehicle depreciation expense of $13,465,822 was charged to functional accounts.

***Schedule Page: 336 Line No.: 12 Column: e***

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

***Schedule Page: 336 Line No.: 12 Column: a***

As discussed in Note 3 of Notes to Financial Statements included in this Form No. 1, the Oregon Public Utility Commission required modifications related to the depreciation lives of coal-fired generating facilities. Below are the affected facilities and the lives and rates required by Oregon.

| Account No. (a) | | Estimated Avg. Service Life (c) | Applied Depr. Rate (Percent) (e) | Average Remaining Life (g) |
|---|---|---|---|---|
| STEAM PRODUCTION PLANT | | | | |
| Hunter Plant | | | | |
| 310.20 | UT | 47.99 | 2.02 | 23.00 |
| 311.00 | UT | 46.78 | 2.32 | 22.49 |
| 312.00 | UT | 42.38 | 2.64 | 21.74 |
| 314.00 | UT | 35.61 | 3.27 | 21.03 |
| 315.00 | UT | 46.47 | 2.30 | 22.61 |
| 316.00 | UT | 41.72 | 2.78 | 19.48 |
| Jim Bridger Plant | | | | |
| 310.20 | WY | 49.44 | 2.03 | 19.00 |
| 311.00 | WY | 45.50 | 2.52 | 18.65 |
| 312.00 | WY | 38.04 | 3.11 | 18.14 |
| 314.00 | WY | 34.06 | 3.58 | 17.65 |
| 315.00 | WY | 47.62 | 2.36 | 18.74 |
| 316.00 | WY | 42.36 | 2.86 | 16.57 |
| Huntington Plant | | | | |
| 311.00 | UT | 50.76 | 2.19 | 23.44 |
| 312.00 | UT | 35.44 | 3.18 | 22.63 |
| 314.00 | UT | 37.69 | 3.08 | 21.86 |
| 315.00 | UT | 48.90 | 2.25 | 23.58 |
| 316.00 | UT | 40.88 | 2.91 | 20.18 |
| Cholla Plant | | | | |
| 310.20 | AZ | 20.00 | 5.00 | |
| 311.00 | AZ | 44.07 | 2.28 | 21.53 |
| 312.00 | AZ | 43.20 | 2.33 | 20.85 |
| 314.00 | AZ | 42.10 | 2.52 | 20.20 |
| 315.00 | AZ | 45.99 | 2.08 | 21.65 |
| 316.00 | AZ | 42.01 | 2.49 | 18.77 |
| Dave Johnston Plant | | | | |
| 310.20 | WY | 50.39 | 2.18 | 17.00 |
| 311.00 | WY | 35.80 | 3.38 | 16.72 |
| 312.00 | WY | 35.75 | 3.43 | 16.32 |
| 314.00 | WY | 37.75 | 3.35 | 15.92 |

| | | | | |
|---|---|---|---|---|
| 315.00 | WY | 44.31 | 2.75 | 16.79 |
| 316.00 | WY | 19.67 | 5.83 | 15.05 |
| | | | | |
| Wyodak Plant | | | | |
| 310.20 | WY | 44.69 | 2.34 | 20.00 |
| 311.00 | WY | 45.67 | 2.45 | 19.61 |
| 312.00 | WY | 40.13 | 2.86 | 19.05 |
| 314.00 | WY | 41.28 | 2.87 | 18.51 |
| 315.00 | WY | 47.47 | 2.31 | 19.71 |
| 316.00 | WY | 30.12 | 3.95 | 17.31 |
| | | | | |
| Naughton Plant | | | | |
| 310.20 | WY | 65.50 | 1.45 | 22.00 |
| 311.00 | WY | 41.81 | 2.65 | 21.53 |
| 312.00 | WY | 38.97 | 2.86 | 20.85 |
| 314.00 | WY | 36.95 | 3.10 | 20.20 |
| 315.00 | WY | 44.52 | 2.45 | 21.65 |
| 316.00 | WY | 44.49 | 2.65 | 18.77 |
| | | | | |
| Colstrip Plant | | | | |
| 311.00 | MT | 46.38 | 2.08 | 25.34 |
| 312.00 | MT | 44.79 | 2.20 | 24.40 |
| 314.00 | MT | 39.83 | 2.66 | 23.49 |
| 315.00 | MT | 47.17 | 1.99 | 25.51 |
| 316.00 | MT | 40.58 | 2.58 | 21.55 |
| | | | | |
| Craig Plant | | | | |
| 311.00 | CO | 45.57 | 2.81 | 19.61 |
| 312.00 | CO | 37.21 | 3.36 | 19.05 |
| 314.00 | CO | 41.43 | 3.21 | 18.51 |
| 315.00 | CO | 46.49 | 2.72 | 19.71 |
| 316.00 | CO | 42.54 | 3.19 | 17.31 |
| | | | | |
| Carbon Plant | | | | |
| 311.00 | UT | 36.71 | 3.44 | 9.91 |
| 312.00 | UT | 28.41 | 4.47 | 9.78 |
| 314.00 | UT | 31.58 | 4.10 | 9.64 |
| 315.00 | UT | 38.65 | 3.22 | 9.93 |
| 316.00 | UT | 36.92 | 3.50 | 9.34 |
| | | | | |
| Hayden Plant | | | | |
| 311.00 | CO | 43.47 | 2.71 | 16.72 |
| 312.00 | CO | 31.36 | 3.76 | 16.32 |
| 314.00 | CO | 40.95 | 2.99 | 15.92 |
| 315.00 | CO | 47.78 | 2.43 | 16.79 |
| 316.00 | CO | 37.79 | 3.29 | 15.05 |

**Schedule Page: 336.17 Line No.: 36 Column: a**

| FERC Sub Acct | Description |
|---|---|
| 310.20 | Land Rights |
| 330.20 | Land Rights |
| 330.30 | Water Rights |
| 330.40 | Flood Rights |
| 330.50 | Land Rights-Fish/Wildlife |
| 350.20 | Land Rights |
| 353.70 | Supervisory Equipment |
| 356.20 | Clearing & Grading |
| 360.20 | Land Rights |
| 362.70 | Supervisory & Alarm Equipment |
| 363.70 | Storage Battery Equipment |
| 369.10 | Overhead Services |
| 369.20 | Underground Services |
| 389.20 | Land Rights |
| 390.30 | Office Panels |
| 391.10 | Mainframe Computers |
| 391.20 | Personal Computers |
| 391.30 | Office Equipment |
| 392.10 | Transp. Eqpt - Light Trucks & Vans |
| 392.30 | Aircraft |
| 392.50 | Transp. Eqpt - Medium Trucks |
| 392.90 | Transp. Eqpt - Trailers |
| 396.30 | Light Power Operated Equipment |
| 396.70 | Heavy Power Operated Equipment |
| 397.20 | Mobile Radio Equipment |
| 399.30 | Structures & Improvements |
| 399.41 | Surface Processing Equip |
| 399.44 | Surface-Electric Power Facil |
| 399.45 | Underground Equipment |
| 399.51 | Vehicles |
| 399.52 | Heavy Construction Equipment |
| 399.60 | Miscellaneous Equipment |
| 399.61 | Computer Equipment |
| 399.70 | Mine Development |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## REGULATORY COMMISSION EXPENSES

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

| Line No. | Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a) | Assessed by Regulatory Commission (b) | Expenses of Utility (c) | Total Expense for Current Year (b) + (c) (d) | Deferred in Account 182.3 at Beginning of Year (e) |
|---|---|---|---|---|---|
| 1 | Before the Public Service Commission of Utah: | | | | |
| 2 | Annual Fee | 3,753,722 | | 3,753,722 | |
| 3 | Other State Regulatory Expenses | | 2,819 | 2,819 | |
| 4 | | | | | |
| 5 | Before the Public Utility Commission of | | | | |
| 6 | Oregon: | | | | |
| 7 | Annual Fee | 2,877,122 | | 2,877,122 | |
| 8 | Other State Regulatory Expenses | | 1,009,743 | 1,009,743 | |
| 9 | | | | | |
| 10 | Before the Public Service Commission of | | | | |
| 11 | Wyoming: | | | | |
| 12 | Annual Fee | 1,099,280 | | 1,099,280 | |
| 13 | Other State Regulatory Expenses | | | | |
| 14 | | | | | |
| 15 | Before the Washington Utilities and | | | | |
| 16 | Transportation Commission: | | | | |
| 17 | Annual Fee | 483,320 | | 483,320 | |
| 18 | Other State Regulatory Expenses | | | | |
| 19 | | | | | |
| 20 | Before the Idaho Public Utilities Commission: | | | | |
| 21 | Annual Fee | 404,139 | | 404,139 | |
| 22 | Other State Regulatory Expenses | | 28,865 | 28,865 | |
| 23 | | | | | |
| 24 | Before the Public Utilities Commission of | | | | |
| 25 | California: | | | | |
| 26 | Annual Fee | 536 | | 536 | |
| 27 | Other State Regulatory Expenses | | 70,777 | 70,777 | |
| 28 | | | | | |
| 29 | Before the Federal Energy Regulatory | | | | |
| 30 | Commission: | | | | |
| 31 | Annual Fee | 1,716,878 | | 1,716,878 | |
| 32 | Annual Land Use Fee | 183,061 | | 183,061 | |
| 33 | | | | | |
| 34 | Deferred Regulatory Commission Expense | | | | 592,973 |
| 35 | | | | | |
| 36 | | | | | |
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| 43 | | | | | |
| 44 | | | | | |
| 45 | | | | | |
| 46 | TOTAL | 10,518,058 | 1,112,204 | 11,630,262 | 592,973 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## REGULATORY COMMISSION EXPENSES (Continued)

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

| EXPENSES INCURRED DURING YEAR | | | | AMORTIZED DURING YEAR | | | |
|---|---|---|---|---|---|---|---|
| CURRENTLY CHARGED TO | | | | | | | |
| Department (f) | Account No. (g) | Amount (h) | Deferred to Account 182.3 (i) | Contra Account (j) | Amount (k) | Deferred in Account 182.3 End of Year (l) | Line No. |
| | | | | | | | 1 |
| Electric | 928 | 3,753,722 | | | | | 2 |
| Electric | 928 | 2,819 | | | | | 3 |
| | | | | | | | 4 |
| | | | | | | | 5 |
| | | | | | | | 6 |
| Electric | 928 | 2,877,122 | | | | | 7 |
| Electric | 928 | 1,009,743 | | | | | 8 |
| | | | | | | | 9 |
| | | | | | | | 10 |
| | | | | | | | 11 |
| Electric | 928 | 1,099,280 | | | | | 12 |
| | | | | | | | 13 |
| | | | | | | | 14 |
| | | | | | | | 15 |
| | | | | | | | 16 |
| Electric | 928 | 483,320 | | | | | 17 |
| | | | | | | | 18 |
| | | | | | | | 19 |
| | | | | | | | 20 |
| Electric | 928 | 404,139 | | | | | 21 |
| Electric | 928 | 28,865 | | | | | 22 |
| | | | | | | | 23 |
| | | | | | | | 24 |
| | | | | | | | 25 |
| Electric | 928 | 536 | | | | | 26 |
| Electric | 928 | 70,777 | | | | | 27 |
| | | | | | | | 28 |
| | | | | | | | 29 |
| | | | | | | | 30 |
| Electric | 928 | 1,716,878 | | | | | 31 |
| Electric | 928 | 183,061 | | | | | 32 |
| | | | | | | | 33 |
| Electric | | | 465,105 | 928 | 1,109,385 | -51,307 | 34 |
| | | | | | | | 35 |
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| | | | | | | | 45 |
| | | 11,630,262 | 465,105 | | 1,109,385 | -51,307 | 46 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

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

Classifications:

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

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

| Line No. | Classification (a) | Description (b) |
|---|---|---|
| 1 | | |
| 2 | | |
| 3 | | |
| 4 | B. Electric R, D & D Performed Externally | |
| 5 | (1) Research Support | Electric Power Research Institute |
| 6 | (1) Research Support | Electric Power Research Institute |
| 7 | (1) Research Support | Electric Power Research Institute |
| 8 | | |
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $5,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $5,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

| Costs Incurred Internally Current Year (c) | Costs Incurred Externally Current Year (d) | AMOUNTS CHARGED IN CURRENT YEAR Account (e) | AMOUNTS CHARGED IN CURRENT YEAR Amount (f) | Unamortized Accumulation (g) | Line No. |
|---|---|---|---|---|---|
| | | | | | 1 |
| | | | | | 2 |
| | | | | | 3 |
| | | | | | 4 |
| | 234,887 | 557 | 234,887 | | 5 |
| | 30,000 | 580 | 30,000 | | 6 |
| | 408,353 | 930.2 | 408,353 | | 7 |
| | | | | | 8 |
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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## DISTRIBUTION OF SALARIES AND WAGES

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

| Line No. | Classification<br>(a) | Direct Payroll Distribution<br>(b) | Allocation of Payroll charged for Clearing Accounts<br>(c) | Total<br>(d) |
|---|---|---|---|---|
| 1 | Electric | | | |
| 2 | Operation | | | |
| 3 | Production | 98,455,737 | | |
| 4 | Transmission | 11,005,747 | | |
| 5 | Regional Market | | | |
| 6 | Distribution | 40,212,401 | | |
| 7 | Customer Accounts | 41,526,643 | | |
| 8 | Customer Service and Informational | 5,116,441 | | |
| 9 | Sales | | | |
| 10 | Administrative and General | 36,419,383 | | |
| 11 | TOTAL Operation (Enter Total of lines 3 thru 10) | 232,736,352 | | |
| 12 | Maintenance | | | |
| 13 | Production | 43,333,252 | | |
| 14 | Transmission | 9,970,922 | | |
| 15 | Regional Market | | | |
| 16 | Distribution | 65,719,228 | | |
| 17 | Administrative and General | 2,732,424 | | |
| 18 | TOTAL Maintenance (Total of lines 13 thru 17) | 121,755,826 | | |
| 19 | Total Operation and Maintenance | | | |
| 20 | Production (Enter Total of lines 3 and 13) | 141,788,989 | | |
| 21 | Transmission (Enter Total of lines 4 and 14) | 20,976,669 | | |
| 22 | Regional Market (Enter Total of Lines 5 and 15) | | | |
| 23 | Distribution (Enter Total of lines 6 and 16) | 105,931,629 | | |
| 24 | Customer Accounts (Transcribe from line 7) | 41,526,643 | | |
| 25 | Customer Service and Informational (Transcribe from line 8) | 5,116,441 | | |
| 26 | Sales (Transcribe from line 9) | | | |
| 27 | Administrative and General (Enter Total of lines 10 and 17) | 39,151,807 | | |
| 28 | TOTAL Oper. and Maint. (Total of lines 20 thru 27) | 354,492,178 | | 354,492,178 |
| 29 | Gas | | | |
| 30 | Operation | | | |
| 31 | Production-Manufactured Gas | | | |
| 32 | Production-Nat. Gas (Including Expl. and Dev.) | | | |
| 33 | Other Gas Supply | | | |
| 34 | Storage, LNG Terminaling and Processing | | | |
| 35 | Transmission | | | |
| 36 | Distribution | | | |
| 37 | Customer Accounts | | | |
| 38 | Customer Service and Informational | | | |
| 39 | Sales | | | |
| 40 | Administrative and General | | | |
| 41 | TOTAL Operation (Enter Total of lines 31 thru 40) | | | |
| 42 | Maintenance | | | |
| 43 | Production-Manufactured Gas | | | |
| 44 | Production-Natural Gas (Including Exploration and Development) | | | |
| 45 | Other Gas Supply | | | |
| 46 | Storage, LNG Terminaling and Processing | | | |
| 47 | Transmission | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/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 Terminaling and Processing (Total of lines 31 thru | | | |
| 56 | Transmission (Lines 35 and 47) | | | |
| 57 | Distribution (Lines 36 and 48) | | | |
| 58 | Customer Accounts (Line 37) | | | |
| 59 | Customer Service and Informational (Line 38) | | | |
| 60 | Sales (Line 39) | | | |
| 61 | Administrative and General (Lines 40 and 49) | | | |
| 62 | TOTAL Operation and Maint. (Total of lines 52 thru 61) | | | |
| 63 | Other Utility Departments | | | |
| 64 | Operation and Maintenance | | | |
| 65 | TOTAL All Utility Dept. (Total of lines 28, 62, and 64) | 354,492,178 | | 354,492,178 |
| 66 | Utility Plant | | | |
| 67 | Construction (By Utility Departments) | | | |
| 68 | Electric Plant | 144,536,727 | | 144,536,727 |
| 69 | Gas Plant | | | |
| 70 | Other (provide details in footnote): | | | |
| 71 | TOTAL Construction (Total of lines 68 thru 70) | 144,536,727 | | 144,536,727 |
| 72 | Plant Removal (By Utility Departments) | | | |
| 73 | Electric Plant | 10,335,956 | | 10,335,956 |
| 74 | Gas Plant | | | |
| 75 | Other (provide details in footnote): | | | |
| 76 | TOTAL Plant Removal (Total of lines 73 thru 75) | 10,335,956 | | 10,335,956 |
| 77 | Other Accounts (Specify, provide details in footnote): | | | |
| 78 | Fuel Stock | 25,300,133 | | 25,300,133 |
| 79 | Miscellaneous Other Income Deductions | 459,804 | | 459,804 |
| 80 | Miscellaneous Nonoperating/Nonutility | 895,839 | | 895,839 |
| 81 | | | | |
| 82 | | | | |
| 83 | | | | |
| 84 | | | | |
| 85 | | | | |
| 86 | | | | |
| 87 | | | | |
| 88 | | | | |
| 89 | | | | |
| 90 | | | | |
| 91 | | | | |
| 92 | | | | |
| 93 | | | | |
| 94 | | | | |
| 95 | TOTAL Other Accounts | 26,655,776 | | 26,655,776 |
| 96 | TOTAL SALARIES AND WAGES | 536,020,637 | | 536,020,637 |

## PURCHASES AND SALES OF ANCILLARY SERVICES

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

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

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

| | | Amount Purchased for the Year | | | Amount Sold for the Year | | |
|---|---|---|---|---|---|---|---|
| | | Usage - Related Billing Determinant | | | Usage - Related Billing Determinant | | |
| Line No. | Type of Ancillary Service (a) | Number of Units (b) | Unit of Measure (c) | Dollars (d) | Number of Units (e) | Unit of Measure (f) | Dollars (g) |
| 1 | Scheduling, System Control and Dispatch | | | | | | 144,444 |
| 2 | Reactive Supply and Voltage | | | | | | |
| 3 | Regulation and Frequency Response | 59,219,156 | MWh | 9,475,065 | 62,048,004 | MWh | 10,117,711 |
| 4 | Energy Imbalance | | | | -146,049 | MWh | -8,378,412 |
| 5 | Operating Reserve - Spinning | 67,863,332 | MWh | 24,710,896 | 70,860,458 | MWh | 25,562,677 |
| 6 | Operating Reserve - Supplement | 67,863,332 | MWh | 24,710,896 | 70,491,920 | MWh | 25,468,389 |
| 7 | Other | | | | 1,389 | MWh | 24,191 |
| 8 | Total (Lines 1 thru 7) | 194,945,820 | | 58,896,857 | 203,255,722 | | 52,939,000 |

## 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: PacifiCorp

| Line No. | Month (a) | Monthly Peak MW - Total (b) | Day of Monthly Peak (c) | Hour of Monthly Peak (d) | Firm Network Service for Self (e) | Firm Network Service for Others (f) | Long-Term Firm Point-to-point Reservations (g) | Other Long-Term Firm Service (h) | Short-Term Firm Point-to-point Reservation (i) | Other Service (j) |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | January | 18,317 | 23 | 800 | 8,924 | 1,035 | 5,059 | | 3,299 | |
| 2 | February | 17,645 | 4 | 1900 | 8,270 | 1,069 | 5,199 | | 3,107 | |
| 3 | March | 17,929 | 5 | 800 | 7,848 | 939 | 5,199 | | 3,943 | |
| 4 | Total for Quarter 1 | 53,891 | | | 25,042 | 3,043 | 15,457 | | 10,349 | |
| 5 | April | 27,632 | 1 | 800 | 7,785 | 706 | 5,327 | | 13,814 | |
| 6 | May | 28,514 | 19 | 1600 | 8,427 | 883 | 5,242 | | 13,962 | |
| 7 | June | 30,499 | 30 | 1400 | 9,371 | 1,021 | 6,102 | | 14,005 | |
| 8 | Total for Quarter 2 | 86,645 | | | 25,583 | 2,610 | 16,671 | | 41,781 | |
| 9 | July | 29,723 | 9 | 1700 | 9,501 | 1,064 | 6,079 | | 13,079 | |
| 10 | August | 29,050 | 14 | 1700 | 9,396 | 1,049 | 6,079 | | 12,526 | |
| 11 | September | 25,935 | 8 | 1700 | 8,080 | 890 | 6,164 | | 10,801 | |
| 12 | Total for Quarter 3 | 84,708 | | | 26,977 | 3,003 | 18,322 | | 36,406 | |
| 13 | October | 25,359 | 1 | 1600 | 7,588 | 820 | 6,172 | | 10,779 | |
| 14 | November | 24,399 | 5 | 1800 | 7,839 | 742 | 5,242 | | 10,576 | |
| 15 | December | 25,839 | 15 | 1800 | 9,176 | 896 | 5,242 | | 10,525 | |
| 16 | Total for Quarter 4 | 75,597 | | | 24,603 | 2,458 | 16,656 | | 31,880 | |
| 17 | Total Year to Date/Year | 300,841 | | | 102,205 | 11,114 | 67,106 | | 120,416 | |

***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: f***
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.: 8 Column: e***
Refer to footnote for line 4 column (e).

***Schedule Page: 400 Line No.: 8 Column: f***
Refer to footnote for line 4 column (f).

***Schedule Page: 400 Line No.: 8 Column: g***
Refer to footnote for line 4 column (g).

***Schedule Page: 400 Line No.: 8 Column: i***
Refer to footnote for line 4 column (i).

***Schedule Page: 400 Line No.: 12 Column: e***
Refer to footnote for line 4 column (e).

***Schedule Page: 400 Line No.: 12 Column: f***
Refer to footnote for line 4 column (f).

***Schedule Page: 400 Line No.: 12 Column: g***
Refer to footnote for line 4 column (g).

***Schedule Page: 400 Line No.: 12 Column: i***
Refer to footnote for line 4 column (i).

***Schedule Page: 400 Line No.: 16 Column: e***
Refer to footnote for line 4 column (e).

***Schedule Page: 400 Line No.: 16 Column: f***
Refer to footnote for line 4 column (f).

***Schedule Page: 400 Line No.: 16 Column: g***
Refer to footnote for line 4 column (g).

***Schedule Page: 400 Line No.: 16 Column: i***
Refer to footnote for line 4 column (i).

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**(Next Page is 401a)**

## 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<br>(a) | MegaWatt Hours<br>(b) | Line No. | Item<br>(a) | MegaWatt Hours<br>(b) |
|---|---|---|---|---|---|
| 1 | SOURCES OF ENERGY | | 21 | DISPOSITION OF ENERGY | |
| 2 | Generation (Excluding Station Use): | | 22 | Sales to Ultimate Consumers (Including Interdepartmental Sales) | 54,361,783 |
| 3 | Steam | 48,568,501 | 23 | Requirements Sales for Resale (See instruction 4, page 311.) | 232,065 |
| 4 | Nuclear | | 24 | Non-Requirements Sales for Resale (See instruction 4, page 311.) | 12,112,911 |
| 5 | Hydro-Conventional | 3,769,918 | 25 | Energy Furnished Without Charge | |
| 6 | Hydro-Pumped Storage | -3,261 | 26 | Energy Used by the Company (Electric Dept Only, Excluding Station Use) | 121,598 |
| 7 | Other | 7,540,570 | 27 | Total Energy Losses | 4,503,710 |
| 8 | Less Energy for Pumping | | 28 | TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20) | 71,332,067 |
| 9 | Net Generation (Enter Total of lines 3 through 8) | 59,875,728 | | | |
| 10 | Purchases | 11,909,498 | | | |
| 11 | Power Exchanges: | | | | |
| 12 | Received | 6,436,684 | | | |
| 13 | Delivered | 6,569,511 | | | |
| 14 | Net Exchanges (Line 12 minus line 13) | -132,827 | | | |
| 15 | Transmission For Other (Wheeling) | | | | |
| 16 | Received | 17,170,080 | | | |
| 17 | Delivered | 17,170,080 | | | |
| 18 | Net Transmission for Other (Line 16 minus line 17) | | | | |
| 19 | Transmission By Others Losses | -320,332 | | | |
| 20 | TOTAL (Enter Total of lines 9, 10, 14, 18 and 19) | 71,332,067 | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## MONTHLY PEAKS AND OUTPUT

(1) Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
(2) Report on line 2 by month the system's output in Megawatt hours for each month.
(3) Report on line 3 by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
(4) Report on line 4 by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
(5) Report on lines 5 and 6 the specified information for each monthly peak load reported on line 4.

NAME OF SYSTEM:

| Line No. | Month (a) | Total Monthly Energy (b) | Monthly Non-Requirments Sales for Resale & Associated Losses (c) | MONTHLY PEAK Megawatts (See Instr. 4) (d) | MONTHLY PEAK Day of Month (e) | MONTHLY PEAK Hour (f) |
|---|---|---|---|---|---|---|
| 29 | January | 6,462,731 | 974,049 | 8,941 | 24 | 0800 PST |
| 30 | February | 5,731,465 | 904,666 | 8,278 | 5 | 0800 PST |
| 31 | March | 6,132,243 | 1,324,170 | 7,848 | 5 | 0800 PST |
| 32 | April | 5,549,787 | 1,034,184 | 7,785 | 1 | 0800 PDT |
| 33 | May | 5,504,926 | 925,681 | 8,427 | 19 | 1600 PDT |
| 34 | June | 5,574,806 | 742,509 | 9,371 | 30 | 1400 PDT |
| 35 | July | 6,420,079 | 800,181 | 9,501 | 9 | 1700 PDT |
| 36 | August | 6,335,848 | 1,066,918 | 9,396 | 14 | 1700 PDT |
| 37 | September | 5,740,575 | 1,168,029 | 8,081 | 8 | 1600 PDT |
| 38 | October | 5,708,090 | 1,056,848 | 7,588 | 1 | 1600 PDT |
| 39 | November | 5,786,144 | 1,110,255 | 7,839 | 5 | 1800 PST |
| 40 | December | 6,385,373 | 1,005,421 | 9,176 | 15 | 1800 PST |
| 41 | TOTAL | 71,332,067 | 12,112,911 | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

| Line No. | Item (a) | Plant Name: *Carbon* (b) | | | Plant Name: *Cholla* (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 | | | 402 | | |
| 7 | Plant Hours Connected to Load | 8625 | | | 7223 | | |
| 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 | 70 | | | 0 | | |
| 12 | Net Generation, Exclusive of Plant Use - KWh | 1204982000 | | | 2510591000 | | |
| 13 | Cost of Plant: Land and Land Rights | 956546 | | | 2415102 | | |
| 14 | Structures and Improvements | 14151830 | | | 55364139 | | |
| 15 | Equipment Costs | 91596954 | | | 449704777 | | |
| 16 | Asset Retirement Costs | 2951381 | | | 39000 | | |
| 17 | Total Cost | 109656711 | | | 507523018 | | |
| 18 | Cost per KW of Installed Capacity (line 17/5) Including | 581.4248 | | | 1225.9010 | | |
| 19 | Production Expenses: Oper, Supv, & Engr | 312553 | | | 1424208 | | |
| 20 | Fuel | 18529823 | | | 49851156 | | |
| 21 | Coolants and Water (Nuclear Plants Only) | 0 | | | 0 | | |
| 22 | Steam Expenses | 1229297 | | | 4623599 | | |
| 23 | Steam From Other Sources | 0 | | | 0 | | |
| 24 | Steam Transferred (Cr) | 0 | | | 0 | | |
| 25 | Electric Expenses | 1860316 | | | 1566174 | | |
| 26 | Misc Steam (or Nuclear) Power Expenses | 5188701 | | | 3273208 | | |
| 27 | Rents | 13989 | | | 3770 | | |
| 28 | Allowances | 0 | | | 0 | | |
| 29 | Maintenance Supervision and Engineering | 0 | | | 2012831 | | |
| 30 | Maintenance of Structures | 224153 | | | 1115728 | | |
| 31 | Maintenance of Boiler (or reactor) Plant | 2713820 | | | 6064085 | | |
| 32 | Maintenance of Electric Plant | 1673829 | | | 1611953 | | |
| 33 | Maintenance of Misc Steam (or Nuclear) Plant | 412789 | | | 3533767 | | |
| 34 | Total Production Expenses | 32159270 | | | 75080479 | | |
| 35 | Expenses per Net KWh | 0.0267 | | | 0.0299 | | |
| 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 | 576654 | 3243 | 0 | 1364249 | 3084 | 0 |
| 39 | Avg Heat Cont - Fuel Burned (btu/indicate if nuclear) | 11951 | 140000 | 0 | 9600 | 130309 | 0 |
| 40 | Avg Cost of Fuel/unit, as Delvd f.o.b. during year | 31.135 | 139.133 | 0.000 | 35.195 | 90.420 | 0.000 |
| 41 | Average Cost of Fuel per Unit Burned | 31.351 | 0.000 | 0.000 | 36.337 | 0.000 | 0.000 |
| 42 | Average Cost of Fuel Burned per Million BTU | 1.282 | 23.662 | 1.313 | 1.820 | 16.521 | 1.830 |
| 43 | Average Cost of Fuel Burned per KWh Net Gen | 0.015 | 0.000 | 0.015 | 0.019 | 0.000 | 0.019 |
| 44 | Average BTU per KWh Net Generation | 11438.543 | 15.824 | 11454.368 | 10433.234 | 6.723 | 10439.957 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

| Plant Name: *Colstrip* (d) | | | Plant Name: *Craig* (e) | | | Plant Name: *Dave Johnston* (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 |
| | | 153 | | | 166 | | | 764 | 6 |
| | | 8782 | | | 8784 | | | 8784 | 7 |
| | | 0 | | | 0 | | | 0 | 8 |
| | | 148 | | | 165 | | | 762 | 9 |
| | | 0 | | | 0 | | | 0 | 10 |
| | | 0 | | | 0 | | | 191 | 11 |
| | | 1234494000 | | | 1368109000 | | | 5638806000 | 12 |
| | | 1355853 | | | 137086 | | | 10451083 | 13 |
| | | 57362857 | | | 36026749 | | | 52148635 | 14 |
| | | 154419435 | | | 129942322 | | | 404891472 | 15 |
| | | 39236 | | | 55971 | | | 6874431 | 16 |
| | | 213177381 | | | 166162128 | | | 474365621 | 17 |
| | | 1370.0346 | | | 965.4975 | | | 580.7610 | 18 |
| | | 17822 | | | 271697 | | | 765017 | 19 |
| | | 14142105 | | | 19394326 | | | 50187768 | 20 |
| | | 0 | | | 0 | | | 0 | 21 |
| | | 795836 | | | 1380265 | | | 5679 | 22 |
| | | 0 | | | 0 | | | 0 | 23 |
| | | 0 | | | 0 | | | 0 | 24 |
| | | 28900 | | | 613813 | | | 0 | 25 |
| | | 2645916 | | | 708500 | | | 15340716 | 26 |
| | | 23546 | | | 0 | | | 31348 | 27 |
| | | 0 | | | 0 | | | 0 | 28 |
| | | 227592 | | | 596071 | | | 0 | 29 |
| | | 288315 | | | 346329 | | | 1861787 | 30 |
| | | 1712259 | | | 3336855 | | | 10190326 | 31 |
| | | 218000 | | | 784868 | | | 8025256 | 32 |
| | | 304467 | | | 807818 | | | 1434677 | 33 |
| | | 20404758 | | | 28240542 | | | 87842574 | 34 |
| | | 0.0165 | | | 0.0206 | | | 0.0156 | 35 |
| Coal | Oil | Composite | Coal | Oil | Composite | Coal | Oil | Composite | 36 |
| Tons | Barrels | | Tons | Barrels | | Tons | Barrels | | 37 |
| 793452 | 671 | 0 | 691557 | 441 | 0 | 4024867 | 10941 | 0 | 38 |
| 8393 | 140000 | 0 | 9933 | 133998 | 0 | 7969 | 140000 | 0 | 39 |
| 16.428 | 134.845 | 0.000 | 28.143 | 115.090 | 0.000 | 12.167 | 122.869 | 0.000 | 40 |
| 17.709 | 0.000 | 0.000 | 27.921 | 0.000 | 0.000 | 12.135 | 0.000 | 0.000 | 41 |
| 0.986 | 22.935 | 0.993 | 1.363 | 20.451 | 1.369 | 0.756 | 20.896 | 0.777 | 42 |
| 0.011 | 0.000 | 0.011 | 0.014 | 0.000 | 0.014 | 0.009 | 0.000 | 0.009 | 43 |
| 10788.946 | 3.197 | 10792.143 | 10041.946 | 1.812 | 10043.758 | 11375.864 | 11.409 | 11387.273 | 44 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## 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: *Hayden* (b) | | | Plant Name: *Hunter Unit No. 1* (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 | | | 406 |
| 7 | Plant Hours Connected to Load | | | 8784 | | | 8323 |
| 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 | | | 0 |
| 12 | Net Generation, Exclusive of Plant Use - KWh | | | 623505000 | | | 3114957000 |
| 13 | Cost of Plant: Land and Land Rights | | | 379735 | | | 9688975 |
| 14 | Structures and Improvements | | | 6002332 | | | 62728682 |
| 15 | Equipment Costs | | | 61376697 | | | 231862809 |
| 16 | Asset Retirement Costs | | | 20877 | | | 1023554 |
| 17 | Total Cost | | | 67779641 | | | 305304020 |
| 18 | Cost per KW of Installed Capacity (line 17/5) Including | | | 833.6979 | | | 689.1739 |
| 19 | Production Expenses: Oper, Supv, & Engr | | | 215629 | | | -5903 |
| 20 | Fuel | | | 11813040 | | | 39811612 |
| 21 | Coolants and Water (Nuclear Plants Only) | | | 0 | | | 0 |
| 22 | Steam Expenses | | | 1070163 | | | 3014808 |
| 23 | Steam From Other Sources | | | 0 | | | 0 |
| 24 | Steam Transferred (Cr) | | | 0 | | | 0 |
| 25 | Electric Expenses | | | 230705 | | | 0 |
| 26 | Misc Steam (or Nuclear) Power Expenses | | | 417080 | | | 2244196 |
| 27 | Rents | | | 0 | | | 29 |
| 28 | Allowances | | | 0 | | | 0 |
| 29 | Maintenance Supervision and Engineering | | | 219300 | | | 0 |
| 30 | Maintenance of Structures | | | 218128 | | | 2206000 |
| 31 | Maintenance of Boiler (or reactor) Plant | | | 1238354 | | | 5245970 |
| 32 | Maintenance of Electric Plant | | | 158508 | | | 1133462 |
| 33 | Maintenance of Misc Steam (or Nuclear) Plant | | | 406135 | | | 157798 |
| 34 | Total Production Expenses | | | 15987042 | | | 53807972 |
| 35 | Expenses per Net KWh | | | 0.0256 | | | 0.0173 |
| 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 | 301473 | 473 | 0 | 1485395 | 3165 | 0 |
| 39 | Avg Heat Cont - Fuel Burned (btu/indicate if nuclear) | 11492 | 132599 | 0 | 11563 | 140000 | 0 |
| 40 | Avg Cost of Fuel/unit, as Delvd f.o.b. during year | 36.807 | 155.123 | 0.000 | 0.000 | 0.000 | 0.000 |
| 41 | Average Cost of Fuel per Unit Burned | 38.859 | 0.000 | 0.000 | 26.498 | 0.000 | 0.000 |
| 42 | Average Cost of Fuel Burned per Million BTU | 1.587 | 27.859 | 1.601 | 1.129 | 24.291 | 1.142 |
| 43 | Average Cost of Fuel Burned per KWh Net Gen | 0.018 | 0.000 | 0.018 | 0.012 | 0.000 | 0.012 |
| 44 | Average BTU per KWh Net Generation | 11113.391 | 4.221 | 11117.613 | 11027.839 | 5.974 | 11033.813 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

| Plant Name: *Hunter Unit No. 2* (d) | | | Plant Name: *Hunter Unit No. 3* (e) | | | Plant Name: *Hunter - Total Plant* (f) | | | Line No. |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |
| | | Steam | | | Steam | | | Steam | 1 |
| | | Outdoor Boiler | | | Outdoor Boiler | | | Outdoor Boiler | 2 |
| | | 1980 | | | 1983 | | | 1978 | 3 |
| | | 1980 | | | 1983 | | | 1983 | 4 |
| | | 285.00 | | | 495.60 | | | 1223.60 | 5 |
| | | 261 | | | 477 | | | 1126 | 6 |
| | | 8617 | | | 8269 | | | 8781 | 7 |
| | | 0 | | | 0 | | | 0 | 8 |
| | | 259 | | | 460 | | | 1122 | 9 |
| | | 0 | | | 0 | | | 0 | 10 |
| | | 0 | | | 0 | | | 220 | 11 |
| | | 2042967000 | | | 3533797000 | | | 8691721000 | 12 |
| | | 9688975 | | | 10275401 | | | 29653351 | 13 |
| | | 51661298 | | | 90839287 | | | 205229267 | 14 |
| | | 154914041 | | | 402601688 | | | 789378538 | 15 |
| | | 1023554 | | | 1023554 | | | 3070663 | 16 |
| | | 217287868 | | | 504739930 | | | 1027331819 | 17 |
| | | 762.4136 | | | 1018.4422 | | | 839.5978 | 18 |
| | | -5903 | | | -5903 | | | -17709 | 19 |
| | | 25535122 | | | 43074989 | | | 108421723 | 20 |
| | | 0 | | | 0 | | | 0 | 21 |
| | | 3015203 | | | 3004795 | | | 9034806 | 22 |
| | | 0 | | | 0 | | | 0 | 23 |
| | | 0 | | | 0 | | | 0 | 24 |
| | | 0 | | | 0 | | | 0 | 25 |
| | | -2248468 | | | 2740942 | | | 2736670 | 26 |
| | | 29 | | | 29 | | | 87 | 27 |
| | | 0 | | | 0 | | | 0 | 28 |
| | | 0 | | | 0 | | | 0 | 29 |
| | | 2064150 | | | 1839573 | | | 6109723 | 30 |
| | | 5230491 | | | 7864514 | | | 18340975 | 31 |
| | | 1247336 | | | 541738 | | | 2922535 | 32 |
| | | 164245 | | | 262578 | | | 584621 | 33 |
| | | 35002205 | | | 59323255 | | | 148133431 | 34 |
| | | 0.0171 | | | 0.0168 | | | 0.0170 | 35 |
| Coal | Oil | Composite | Coal | Oil | Composite | Coal | Oil | Composite | 36 |
| Tons | Barrels | | Tons | Barrels | | Tons | Barrels | | 37 |
| 952476 | 750 | 0 | 1569283 | 11091 | 0 | 4007154 | 15006 | 0 | 38 |
| 11607 | 140000 | 0 | 11540 | 140000 | 0 | 11570 | 140000 | 0 | 39 |
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 26.252 | 136.486 | 0.000 | 40 |
| 26.709 | 0.000 | 0.000 | 26.493 | 0.000 | 0.000 | 26.546 | 0.000 | 0.000 | 41 |
| 1.125 | 21.656 | 1.129 | 1.132 | 23.009 | 1.172 | 1.129 | 23.212 | 1.150 | 42 |
| 0.012 | 0.000 | 0.012 | 0.012 | 0.000 | 0.012 | 0.012 | 0.000 | 0.012 | 43 |
| 10822.880 | 2.159 | 10825.039 | 10249.329 | 18.454 | 10267.783 | 10668.301 | 10.151 | 10678.452 | 44 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## 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: *Huntington* (b) | | | Plant Name: *Jim Bridger* (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) | | | 906 | | | 1405 |
| 7 | Plant Hours Connected to Load | | | 8770 | | | 8784 |
| 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 | | | 164 | | | 345 |
| 12 | Net Generation, Exclusive of Plant Use - KWh | | | 7148850000 | | | 10164833000 |
| 13 | Cost of Plant: Land and Land Rights | | | 2386782 | | | 1161925 |
| 14 | Structures and Improvements | | | 111555214 | | | 135138580 |
| 15 | Equipment Costs | | | 516465783 | | | 814872756 |
| 16 | Asset Retirement Costs | | | 2351856 | | | 6663361 |
| 17 | Total Cost | | | 632759635 | | | 957836622 |
| 18 | Cost per KW of Installed Capacity (line 17/5) Including | | | 635.3008 | | | 621.5279 |
| 19 | Production Expenses: Oper, Supv, & Engr | | | 15251 | | | 18053815 |
| 20 | Fuel | | | 81271884 | | | 149060097 |
| 21 | Coolants and Water (Nuclear Plants Only) | | | 0 | | | 0 |
| 22 | Steam Expenses | | | 8595373 | | | 3610169 |
| 23 | Steam From Other Sources | | | 0 | | | 0 |
| 24 | Steam Transferred (Cr) | | | 0 | | | 0 |
| 25 | Electric Expenses | | | 0 | | | 2475 |
| 26 | Misc Steam (or Nuclear) Power Expenses | | | 10267855 | | | -15463153 |
| 27 | Rents | | | 14493 | | | 186164 |
| 28 | Allowances | | | 0 | | | 0 |
| 29 | Maintenance Supervision and Engineering | | | 1245563 | | | 500548 |
| 30 | Maintenance of Structures | | | 1550821 | | | 11080899 |
| 31 | Maintenance of Boiler (or reactor) Plant | | | 6866869 | | | 23148750 |
| 32 | Maintenance of Electric Plant | | | 1244964 | | | 7676159 |
| 33 | Maintenance of Misc Steam (or Nuclear) Plant | | | 1212918 | | | 2726422 |
| 34 | Total Production Expenses | | | 112285991 | | | 200582345 |
| 35 | Expenses per Net KWh | | | 0.0157 | | | 0.0197 |
| 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 | 3004101 | 8288 | 0 | 5688443 | 18419 | 0 |
| 39 | Avg Heat Cont - Fuel Burned (btu/indicate if nuclear) | 11857 | 140000 | 0 | 9249 | 140000 | 0 |
| 40 | Avg Cost of Fuel/unit, as Delvd f.o.b. during year | 25.199 | 126.335 | 0.000 | 25.790 | 119.988 | 0.000 |
| 41 | Average Cost of Fuel per Unit Burned | 26.705 | 0.000 | 0.000 | 25.816 | 0.000 | 0.000 |
| 42 | Average Cost of Fuel Burned per Million BTU | 1.092 | 21.486 | 1.106 | 1.389 | 20.406 | 1.409 |
| 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 | 9965.170 | 6.817 | 9971.986 | 10351.518 | 10.655 | 10362.172 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

| Plant Name: *Naughton* (d) | Plant Name: *Wyodak* (e) | Plant Name: *Gadsby Steam Plant* (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 |
| 705 | 280 | 219 | 6 |
| 8784 | 8454 | 3079 | 7 |
| 0 | 0 | 0 | 8 |
| 700 | 268 | 235 | 9 |
| 0 | 0 | 0 | 10 |
| 144 | 69 | 39 | 11 |
| 5114409000 | 2252799000 | 232078000 | 12 |
| 4290826 | 210526 | 1252090 | 13 |
| 65636170 | 49014021 | 15055364 | 14 |
| 331940962 | 274990749 | 57668039 | 15 |
| 2650267 | 613826 | 587008 | 16 |
| 404518225 | 324829122 | 74562501 | 17 |
| 571.9998 | 1121.2603 | 289.4507 | 18 |
| 461800 | 206365 | 78893 | 19 |
| 76503802 | 19521169 | 26301622 | 20 |
| 0 | 0 | 0 | 21 |
| 7377173 | 0 | 0 | 22 |
| 0 | 0 | 0 | 23 |
| 0 | 0 | 0 | 24 |
| 920 | 0 | 0 | 25 |
| 8591754 | 4112755 | 3446842 | 26 |
| 0 | 4958 | 0 | 27 |
| 0 | 0 | 0 | 28 |
| 1206951 | 48 | 0 | 29 |
| 1139518 | 356591 | 246773 | 30 |
| 5974226 | 5548421 | 1291713 | 31 |
| 1793996 | 1053128 | 1221612 | 32 |
| 636100 | 366653 | 262672 | 33 |
| 103686240 | 31170088 | 32850127 | 34 |
| 0.0203 | 0.0138 | 0.1415 | 35 |

| (d) | (d) | (d) | (e) | (e) | (e) | (f) | (f) | (f) | Line No. |
|---|---|---|---|---|---|---|---|---|---|
| Coal | Gas | Composite | Coal | Oil | Composite | Gas | | | 36 |
| Tons | MCF | | Tons | Barrels | | MCF | | | 37 |
| 2767902 | 163367 | 0 | 1657686 | 3680 | 0 | 3124563 | 0 | 0 | 38 |
| 9858 | 1047 | 0 | 7821 | 140000 | 0 | 1057 | 0 | 0 | 39 |
| 27.315 | 0.000 | 0.000 | 11.511 | 122.186 | 0.000 | 0.000 | 0.000 | 0.000 | 40 |
| 27.117 | 8.863 | 0.000 | 11.505 | 0.000 | 0.000 | 8.418 | 0.000 | 0.000 | 41 |
| 1.374 | 8.448 | 1.396 | 0.736 | 20.780 | 0.753 | 7.961 | 0.000 | 0.000 | 42 |
| 0.015 | 0.000 | 0.015 | 0.008 | 0.000 | 0.008 | 0.113 | 0.000 | 0.000 | 43 |
| 10670.417 | 33.514 | 10703.931 | 11509.918 | 9.606 | 11519.524 | 14236.623 | 0.000 | 0.000 | 44 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## 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: *Little Mountain* (b) | | | Plant Name: Hermiston (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 | 8040 | | | 8389 | | |
| 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 | 109568000 | | | 1801625000 | | |
| 13 | Cost of Plant: Land and Land Rights | 635 | | | 842245 | | |
| 14 | Structures and Improvements | 267331 | | | 12839845 | | |
| 15 | Equipment Costs | 5092337 | | | 155460639 | | |
| 16 | Asset Retirement Costs | 0 | | | 214373 | | |
| 17 | Total Cost | 5360303 | | | 169357102 | | |
| 18 | Cost per KW of Installed Capacity (line 17/5) Including | 335.0189 | | | 605.7121 | | |
| 19 | Production Expenses: Oper, Supv, & Engr | 0 | | | 0 | | |
| 20 | Fuel | 16778091 | | | 56237364 | | |
| 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 | 947555 | | | 7644957 | | |
| 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 | 91556 | | | 0 | | |
| 33 | Maintenance of Misc Steam (or Nuclear) Plant | 0 | | | 0 | | |
| 34 | Total Production Expenses | 17817202 | | | 63882321 | | |
| 35 | Expenses per Net KWh | 0.1626 | | | 0.0355 | | |
| 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 | 2026700 | 0 | 0 | 12834969 | 0 | 0 |
| 39 | Avg Heat Cont - Fuel Burned (btu/indicate if nuclear) | 1058 | 0 | 0 | 1020 | 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 | 8.279 | 0.000 | 0.000 | 4.382 | 0.000 | 0.000 |
| 42 | Average Cost of Fuel Burned per Million BTU | 7.827 | 0.000 | 0.000 | 4.301 | 0.000 | 0.000 |
| 43 | Average Cost of Fuel Burned per KWh Net Gen | 0.153 | 0.000 | 0.000 | 0.031 | 0.000 | 0.000 |
| 44 | Average BTU per KWh Net Generation | 19564.809 | 0.000 | 0.000 | 7258.235 | 0.000 | 0.000 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

| Plant Name: Blundell (d) | Plant Name: Camas Co-Gen (e) | Plant Name: West Valley (f) | Line No. |
|---|---|---|---|
| Steam - Geothermal | Steam | Gas Turbine | 1 |
| Indoor | Outdoor Boiler | Outdoor | 2 |
| 1984 | 1996 | 2002 | 3 |
| 2007 | 1996 | 2002 | 4 |
| 38.10 | 61.50 | 217.00 | 5 |
| 37 | 46 | 194 | 6 |
| 8338 | 7267 | 1757 | 7 |
| 0 | 0 | 0 | 8 |
| 34 | 22 | 202 | 9 |
| 0 | 0 | 0 | 10 |
| 22 | 0 | 6 | 11 |
| 254277000 | 86302000 | 126285000 | 12 |
| 41195596 | 0 | 0 | 13 |
| 7404973 | 5733734 | 0 | 14 |
| 66334256 | 28716806 | 0 | 15 |
| 1336278 | 0 | 0 | 16 |
| 116271103 | 34450540 | 0 | 17 |
| 3051.7350 | 560.1714 | 0.0000 | 18 |
| 33075 | 0 | 0 | 19 |
| 0 | 0 | 10992119 | 20 |
| 0 | 0 | 0 | 21 |
| -234842 | 0 | 0 | 22 |
| 3371385 | 0 | 0 | 23 |
| 0 | 0 | 0 | 24 |
| 0 | 0 | 3006572 | 25 |
| 2291026 | 145433 | 0 | 26 |
| 3024 | 0 | 4583304 | 27 |
| 0 | 0 | 0 | 28 |
| 0 | 0 | 0 | 29 |
| 295344 | 0 | 166275 | 30 |
| 248805 | 0 | 0 | 31 |
| 489274 | 0 | 314608 | 32 |
| 63391 | 6 | 0 | 33 |
| 6560482 | 145439 | 19062878 | 34 |
| 0.0258 | 0.0017 | 0.1510 | 35 |

| (d) | (d) | (d) | (e) | (e) | (e) | (f) | (f) | (f) | Line No. |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Gas | | | 36 |
| | | | | | | MCF | | | 37 |
| 0 | 0 | 0 | 0 | 0 | 0 | 1402458 | 0 | 0 | 38 |
| 0 | 0 | 0 | 0 | 0 | 0 | 1056 | 0 | 0 | 39 |
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 40 |
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 7.838 | 0.000 | 0.000 | 41 |
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 7.485 | 0.000 | 0.000 | 42 |
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.087 | 0.000 | 0.000 | 43 |
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 11629.156 | 0.000 | 0.000 | 44 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## 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: *Gadsby Gas Peakers* (b) | | | Plant Name: *Currant Creek* (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 | | | 571 | | |
| 7 | Plant Hours Connected to Load | 4156 | | | 7752 | | |
| 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 | 250518000 | | | 2799585000 | | |
| 13 | Cost of Plant: Land and Land Rights | 0 | | | 3403277 | | |
| 14 | Structures and Improvements | 4121643 | | | 43236674 | | |
| 15 | Equipment Costs | 71880691 | | | 304844265 | | |
| 16 | Asset Retirement Costs | 0 | | | 134848 | | |
| 17 | Total Cost | 76002334 | | | 351619064 | | |
| 18 | Cost per KW of Installed Capacity (line 17/5) Including | 539.0236 | | | 620.2488 | | |
| 19 | Production Expenses: Oper, Supv, & Engr | 0 | | | 92344 | | |
| 20 | Fuel | 23997222 | | | 157074310 | | |
| 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 | 1555365 | | | 2503145 | | |
| 26 | Misc Steam (or Nuclear) Power Expenses | 0 | | | 0 | | |
| 27 | Rents | 0 | | | 1206 | | |
| 28 | Allowances | 0 | | | 0 | | |
| 29 | Maintenance Supervision and Engineering | 0 | | | 0 | | |
| 30 | Maintenance of Structures | 113442 | | | 405205 | | |
| 31 | Maintenance of Boiler (or reactor) Plant | 0 | | | 0 | | |
| 32 | Maintenance of Electric Plant | 915946 | | | 2906153 | | |
| 33 | Maintenance of Misc Steam (or Nuclear) Plant | 0 | | | 0 | | |
| 34 | Total Production Expenses | 26581975 | | | 162982363 | | |
| 35 | Expenses per Net KWh | 0.1061 | | | 0.0582 | | |
| 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 | 2882672 | 0 | 0 | 19384161 | 0 | 0 |
| 39 | Avg Heat Cont - Fuel Burned (btu/indicate if nuclear) | 1057 | 0 | 0 | 1054 | 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 | 8.325 | 0.000 | 0.000 | 8.103 | 0.000 | 0.000 |
| 42 | Average Cost of Fuel Burned per Million BTU | 7.878 | 0.000 | 0.000 | 7.686 | 0.000 | 0.000 |
| 43 | Average Cost of Fuel Burned per KWh Net Gen | 0.096 | 0.000 | 0.000 | 0.056 | 0.000 | 0.000 |
| 44 | Average BTU per KWh Net Generation | 12158.823 | 0.000 | 0.000 | 7299.697 | 0.000 | 0.000 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

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

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

| Plant Name: *Lake Side* (d) | Plant Name: *Chehalis* (e) | Plant Name: (f) | Line No. |
|---|---|---|---|
| | | | |
| Combined Cycle | Combined Cycle | | 1 |
| Outdoor | Outdoor | | 2 |
| 2007 | 2003 | | 3 |
| 2007 | 2003 | | 4 |
| 548.00 | 520.00 | 0.00 | 5 |
| 601 | 525 | 0 | 6 |
| 7234 | 1686 | 0 | 7 |
| 0 | 0 | 0 | 8 |
| 548 | 520 | 0 | 9 |
| 0 | 0 | 0 | 10 |
| 19 | 17 | 0 | 11 |
| 2861722000 | 588458000 | 0 | 12 |
| 17296760 | 0 | 0 | 13 |
| 27057001 | 0 | 0 | 14 |
| 305014470 | 0 | 0 | 15 |
| 0 | 0 | 0 | 16 |
| 349368231 | 0 | 0 | 17 |
| 637.5333 | 0.0000 | 0.0000 | 18 |
| 126122 | 0 | 0 | 19 |
| 157112030 | 42288408 | 0 | 20 |
| 0 | 0 | 0 | 21 |
| 0 | 0 | 0 | 22 |
| 0 | 0 | 0 | 23 |
| 0 | 0 | 0 | 24 |
| 2712172 | 1301982 | 0 | 25 |
| 0 | 0 | 0 | 26 |
| 0 | 27423 | 0 | 27 |
| 0 | 0 | 0 | 28 |
| 0 | 0 | 0 | 29 |
| 585449 | 9978 | 0 | 30 |
| 0 | 0 | 0 | 31 |
| 1650854 | 515059 | 0 | 32 |
| 0 | 0 | 0 | 33 |
| 162186627 | 44142850 | 0 | 34 |
| 0.0567 | 0.0750 | 0.0000 | 35 |

| (d) | (d) | (d) | (e) | (e) | (e) | (f) | (f) | (f) | Line No. |
|---|---|---|---|---|---|---|---|---|---|
| Gas | | | Gas | | | | | | 36 |
| MCF | | | MCF | | | | | | 37 |
| 19419993 | 0 | 0 | 4188285 | 0 | 0 | 0 | 0 | 0 | 38 |
| 1042 | 0 | 0 | 1030 | 0 | 0 | 0 | 0 | 0 | 39 |
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 40 |
| 8.090 | 0.000 | 0.000 | 10.097 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 41 |
| 7.767 | 0.000 | 0.000 | 13.478 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 42 |
| 0.055 | 0.000 | 0.000 | 0.072 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 43 |
| 7068.652 | 0.000 | 0.000 | 5331.917 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 44 |

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

Cholla Plant is operated by Arizona Public Service Company. Respondent owns Unit No. 4 plus 37.44% 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 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 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 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 is owned by respondent and Provo City Corporation with undivided interest of 93.75% and 6.25% respectively. Data reported in column (c) represents respondent's share.

***Schedule Page: 402.1 Line No.: -1 Column: d***

Hunter Plant Unit No. 2 is owned by respondent, Deseret Power Electric Cooperative, and Utah Associated Municipal Power Systems, each with undivided interest of 60.31%, 25.108%, and 14.582% respectively. Data reported in column (d) represents respondent's share.

***Schedule Page: 402.1 Line No.: -1 Column: f***

Hunter Unit No. 1 is owned by respondent and Provo City Corporation with undivided interest of 93.75% and 6.25% respectively. Hunter Unit No. 2 is owned by respondent, Deseret Power Electric Cooperative, and Utah Associated Municipal Power Systems, each with undivided interest of 60.31%, 25.108%, and 14.582% respectively. Data in column (f) represents respondent's share.

***Schedule Page: 402.2 Line No.: -1 Column: c***

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%.

***Schedule Page: 402.2 Line No.: -1 Column: e***

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%.

***Schedule Page: 402.3 Line No.: -1 Column: c***

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 326.7 Row 14 of this Form No. 1 for further information on Hermiston Generating Company, L.P.

***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***

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***

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 a subsidiary of PPM Energy, Inc. ("PPM"), which is a direct subsidiary of PHI and an indirect subsidiary of ScottishPower. 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 West Valley lease. PacifiCorp subsequently exercised its right to rescind the termination on September 28, 2004 after determining, through a public process, that the resource could not be replaced on a more economic basis and without increasing risks to system reliability. PacifiCorp has a second option to terminate the West Valley lease if written notice is provided to West Valley on or before December 1, 2006. PacifiCorp is committed to future minimum lease payments of $15.0 million annually for years ending March 31, 2005 through 2008 and $2.5 million for the year ending March 31, 2009.

***Schedule Page: 402.4 Line No.: -1 Column: e***

**Chehalis**

On September 15, 2008, after having received the required regulatory approvals, PacifiCorp acquired from TNA Merchant Projects, Inc., an affiliate of Suez Energy North America, Inc., 100% of the equity interests of Chehalis Power Generating, LLC, an entity owning a 520-megawatt ("MW") natural gas-fired generating plant located in Chehalis, Washington. The total cash purchase price was $308 million and the estimated fair value of the acquired entity was primarily allocated to the plant. Chehalis Power Generating, LLC was merged into PacifiCorp immediately following the acquisition. The results of the plant's operations have been included in PacifiCorp's Financial Statements since the acquisition date.

In February 2009, PacifiCorp filed with the FERC under docket number AC09-41-000 a request to clear account 102 Electric Plant Purchased or Sold, for costs incurred to acquire the 520-MW natural gas-fired Chehalis generating plant. The cost of plant on lines 13 through 17 on page 403.4 included in this Form No. 1 for the Chehalis generating plant is blank as the costs are included in account 102 Electric Plant Purchased or Sold at December 31, 2008.

***Schedule Page: 402 Line No.: 36 Column: b2***

**Carbon**

Fuel oil is used for start-up purposes.

***Schedule Page: 402 Line No.: 36 Column: f2***

**Dave Johnston**

Fuel oil is used for start-up purposes.

***Schedule Page: 402.1 Line No.: 36 Column: e2***

**Hunter Plant Unit No. 3**

Fuel oil is used for start-up purposes.

***Schedule Page: 402.2 Line No.: 36 Column: b2***

**Huntington**

Fuel oil is used for start-up purposes.

***Schedule Page: 402.2 Line No.: 36 Column: d2***

**Naughton**

Natural gas is used for start-up purposes.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

| Line No. | Item (a) | FERC Licensed Project No. 2082<br>Plant Name: Copco No. 1<br>(b) | FERC Licensed Project No. 2082<br>Plant Name: Copco No. 2<br>(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 | 30 |
| 7 | Plant Hours Connect to Load | 6,377 | 6,145 |
| 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 | 97,312,000 | 120,286,000 |
| 13 | Cost of Plant | | |
| 14 | Land and Land Rights | 180,375 | 20,914 |
| 15 | Structures and Improvements | 1,244,996 | 2,153,777 |
| 16 | Reservoirs, Dams, and Waterways | 2,646,478 | 2,954,625 |
| 17 | Equipment Costs | 4,630,508 | 10,260,704 |
| 18 | Roads, Railroads, and Bridges | 105,442 | 240,200 |
| 19 | Asset Retirement Costs | 0 | 0 |
| 20 | TOTAL cost (Total of 14 thru 19) | 8,807,799 | 15,630,220 |
| 21 | Cost per KW of Installed Capacity (line 20 / 5) | 440.3900 | 578.8970 |
| 22 | Production Expenses | | |
| 23 | Operation Supervision and Engineering | 210,140 | 263,473 |
| 24 | Water for Power | 1,252 | 1,691 |
| 25 | Hydraulic Expenses | 498 | 672 |
| 26 | Electric Expenses | 0 | 0 |
| 27 | Misc Hydraulic Power Generation Expenses | 386,254 | 527,780 |
| 28 | Rents | -612 | -753 |
| 29 | Maintenance Supervision and Engineering | 0 | 0 |
| 30 | Maintenance of Structures | 7,068 | 18,174 |
| 31 | Maintenance of Reservoirs, Dams, and Waterways | 14,338 | 76,690 |
| 32 | Maintenance of Electric Plant | 32,660 | 55,381 |
| 33 | Maintenance of Misc Hydraulic Plant | 15,487 | 20,907 |
| 34 | Total Production Expenses (total 23 thru 33) | 667,085 | 964,015 |
| 35 | Expenses per net KWh | 0.0069 | 0.0080 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

| FERC Licensed Project No. 1927<br>Plant Name: Clearwater No. 1<br>(d) | FERC Licensed Project No. 1927<br>Plant Name: Clearwater No. 2<br>(e) | FERC Licensed Project No. 2420<br>Plant Name: Cutler<br>(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 | 19 | 21 | 6 |
| 8,661 | 6,780 | 4,082 | 7 |
| | | | 8 |
| 18 | 31 | 29 | 9 |
| 18 | 31 | 29 | 10 |
| 1 | 1 | 4 | 11 |
| 42,259,000 | 43,375,000 | 53,882,000 | 12 |
| | | | 13 |
| 0 | 0 | 3,505,129 | 14 |
| 562,143 | 1,269,008 | 3,809,645 | 15 |
| 4,776,586 | 10,472,776 | 6,669,473 | 16 |
| 1,034,775 | 1,331,572 | 14,160,572 | 17 |
| 39,142 | 250,151 | 572,059 | 18 |
| 0 | 0 | 0 | 19 |
| 6,412,646 | 13,323,507 | 28,716,878 | 20 |
| 427.5097 | 512.4426 | 957.2293 | 21 |
| | | | 22 |
| 113,261 | 209,150 | 174,052 | 23 |
| 12,518 | 21,698 | 1,879 | 24 |
| 63,287 | 109,698 | 77,526 | 25 |
| 0 | 0 | 0 | 26 |
| 262,697 | 422,499 | 689,349 | 27 |
| 2,624 | 4,549 | -63 | 28 |
| 0 | 0 | 0 | 29 |
| 14,972 | 38,448 | 4,338 | 30 |
| 17,319 | 37,024 | 23,308 | 31 |
| 16,353 | 53,458 | 4,796 | 32 |
| 47,409 | 82,660 | 266,438 | 33 |
| 550,440 | 979,184 | 1,241,623 | 34 |
| 0.0130 | 0.0226 | 0.0230 | 35 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

| Line No. | Item<br>(a) | FERC Licensed Project No. 1927<br>Plant Name: Fish Creek<br>(b) | FERC Licensed Project No. 20<br>Plant Name: Grace<br>(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 | 31 |
| 7 | Plant Hours Connect to Load | 5,153 | 7,169 |
| 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 | 3 |
| 12 | Net Generation, Exclusive of Plant Use - Kwh | 32,544,000 | 61,371,000 |
| 13 | Cost of Plant | | |
| 14 | Land and Land Rights | 0 | 62,169 |
| 15 | Structures and Improvements | 665,878 | 1,432,117 |
| 16 | Reservoirs, Dams, and Waterways | 9,961,504 | 9,212,586 |
| 17 | Equipment Costs | 1,307,299 | 4,073,842 |
| 18 | Roads, Railroads, and Bridges | 472,045 | 65,826 |
| 19 | Asset Retirement Costs | 0 | 0 |
| 20 | TOTAL cost (Total of 14 thru 19) | 12,406,726 | 14,846,540 |
| 21 | Cost per KW of Installed Capacity (line 20 / 5) | 1,127.8842 | 449.8952 |
| 22 | Production Expenses | | |
| 23 | Operation Supervision and Engineering | 104,523 | 165,549 |
| 24 | Water for Power | 9,180 | 2,066 |
| 25 | Hydraulic Expenses | 46,411 | 95,567 |
| 26 | Electric Expenses | 0 | 0 |
| 27 | Misc Hydraulic Power Generation Expenses | 216,871 | 1,390,800 |
| 28 | Rents | 1,924 | -221 |
| 29 | Maintenance Supervision and Engineering | 0 | 0 |
| 30 | Maintenance of Structures | 11,613 | 26,490 |
| 31 | Maintenance of Reservoirs, Dams, and Waterways | 48,104 | 69,834 |
| 32 | Maintenance of Electric Plant | 20,736 | 55,527 |
| 33 | Maintenance of Misc Hydraulic Plant | 35,056 | 92,364 |
| 34 | Total Production Expenses (total 23 thru 33) | 494,418 | 1,897,976 |
| 35 | Expenses per net KWh | 0.0152 | 0.0309 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

| FERC Licensed Project No. 2082<br>Plant Name: Iron Gate<br>(d) | FERC Licensed Project No. 2082<br>Plant Name: JC Boyle<br>(e) | FERC Licensed Project No. 1927<br>Plant Name: Lemolo No. 1<br>(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 | 82 | 32 | 6 |
| 8,613 | 7,019 | 8,594 | 7 |
| | | | 8 |
| 19 | 83 | 32 | 9 |
| 19 | 83 | 32 | 10 |
| 1 | 2 | 1 | 11 |
| 125,383,000 | 276,946,000 | 148,606,000 | 12 |
| | | | 13 |
| 341,706 | 26,277 | 0 | 14 |
| 4,186,464 | 2,403,621 | 781,417 | 15 |
| 12,950,361 | 14,538,701 | 9,633,465 | 16 |
| 2,212,967 | 14,986,346 | 5,933,909 | 17 |
| 1,076,116 | 886,710 | 475,419 | 18 |
| 0 | 0 | 0 | 19 |
| 20,767,614 | 32,841,655 | 16,824,210 | 20 |
| 1,153.7563 | 335.1873 | 525.9209 | 21 |
| | | | 22 |
| 240,433 | 468,035 | 255,452 | 23 |
| 1,127 | 6,135 | 26,697 | 24 |
| 448 | 2,440 | 134,971 | 25 |
| 0 | 0 | 0 | 26 |
| 362,073 | 683,410 | 550,438 | 27 |
| -550 | 428 | 5,597 | 28 |
| 0 | 0 | 0 | 29 |
| 576,016 | 73,656 | 42,628 | 30 |
| 13,399 | 40,202 | 49,716 | 31 |
| 49,453 | 27,635 | 56,644 | 32 |
| 13,938 | 107,245 | 100,693 | 33 |
| 1,256,337 | 1,409,186 | 1,222,836 | 34 |
| 0.0100 | 0.0051 | 0.0082 | 35 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

| Line No. | Item (a) | FERC Licensed Project No. 1927<br>Plant Name: Lemolo No. 2<br>(b) | FERC Licensed Project No. 935<br>Plant Name: Merwin<br>(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 | 8,630 | 8,784 |
| 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 | 2 |
| 12 | Net Generation, Exclusive of Plant Use - Kwh | 153,208,000 | 481,775,000 |
| 13 | Cost of Plant | | |
| 14 | Land and Land Rights | 0 | 1,086,417 |
| 15 | Structures and Improvements | 1,106,883 | 28,585,791 |
| 16 | Reservoirs, Dams, and Waterways | 17,780,170 | 9,988,622 |
| 17 | Equipment Costs | 2,089,025 | 14,557,771 |
| 18 | Roads, Railroads, and Bridges | 1,649,779 | 2,230,484 |
| 19 | Asset Retirement Costs | 0 | 0 |
| 20 | TOTAL cost (Total of 14 thru 19) | 22,625,857 | 56,449,085 |
| 21 | Cost per KW of Installed Capacity (line 20 / 5) | 685.6320 | 415.0668 |
| 22 | Production Expenses | | |
| 23 | Operation Supervision and Engineering | 247,497 | 1,085,738 |
| 24 | Water for Power | 27,540 | 28,594 |
| 25 | Hydraulic Expenses | 139,232 | 697,709 |
| 26 | Electric Expenses | 0 | 0 |
| 27 | Misc Hydraulic Power Generation Expenses | 546,491 | 1,108,886 |
| 28 | Rents | 5,773 | 2,664 |
| 29 | Maintenance Supervision and Engineering | 0 | 0 |
| 30 | Maintenance of Structures | 49,485 | 11,620 |
| 31 | Maintenance of Reservoirs, Dams, and Waterways | 51,236 | 8,932 |
| 32 | Maintenance of Electric Plant | 30,954 | 69,329 |
| 33 | Maintenance of Misc Hydraulic Plant | 103,616 | 130,903 |
| 34 | Total Production Expenses (total 23 thru 33) | 1,201,824 | 3,144,375 |
| 35 | Expenses per net KWh | 0.0078 | 0.0065 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

| FERC Licensed Project No. 1927<br>Plant Name: Toketee<br>(d) | FERC Licensed Project No. 20<br>Plant Name: Oneida<br>(e) | FERC Licensed Project No. 2630<br>Plant Name: Prospect No. 2<br>(f) | Line No. |
|---|---|---|---|
| | | | |
| | | | |
| Storage | Storage | Run-of River | 1 |
| Conventional | Conventional | Conventional | 2 |
| 1949 | 1915 | 1928 | 3 |
| 1950 | 1920 | 1928 | 4 |
| 42.50 | 30.00 | 32.00 | 5 |
| 45 | 19 | 36 | 6 |
| 8,415 | 8,783 | 8,718 | 7 |
| | | | 8 |
| 45 | 28 | 36 | 9 |
| 45 | 28 | 36 | 10 |
| 1 | 2 | 1 | 11 |
| 218,891,000 | 34,616,000 | 239,349,000 | 12 |
| | | | 13 |
| 0 | 36,698 | 105,168 | 14 |
| 1,611,846 | 1,378,703 | 2,693,034 | 15 |
| 8,342,707 | 5,104,685 | 23,907,861 | 16 |
| 3,198,682 | 4,721,365 | 3,497,552 | 17 |
| 214,603 | 495,810 | 255,486 | 18 |
| 0 | 0 | 0 | 19 |
| 13,367,838 | 11,737,261 | 30,459,101 | 20 |
| 314.5374 | 391.2420 | 951.8469 | 21 |
| | | | 22 |
| 352,475 | 149,613 | 618,349 | 23 |
| 35,468 | 1,879 | 2,004 | 24 |
| 179,314 | 86,879 | 797 | 25 |
| 0 | 0 | 0 | 26 |
| 652,918 | 758,142 | 424,904 | 27 |
| 7,435 | -201 | 2,635 | 28 |
| 0 | 0 | 0 | 29 |
| 84,033 | 14,828 | 29,198 | 30 |
| 65,862 | 2,699 | 191,894 | 31 |
| 118,726 | 83,686 | 32,350 | 32 |
| 133,444 | 57,040 | 70,547 | 33 |
| 1,629,675 | 1,154,565 | 1,372,678 | 34 |
| 0.0074 | 0.0334 | 0.0057 | 35 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

| Line No. | Item (a) | FERC Licensed Project No. 1927<br>Plant Name: Slide Creek (b) | FERC Licensed Project No. 20<br>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 | 9 |
| 7 | Plant Hours Connect to Load | 8,636 | 5,391 |
| 8 | Net Plant Capability (in megawatts) | | |
| 9 | (a) Under Most Favorable Oper Conditions | 18 | 14 |
| 10 | (b) Under the Most Adverse Oper Conditions | 18 | 14 |
| 11 | Average Number of Employees | 1 | 2 |
| 12 | Net Generation, Exclusive of Plant Use - Kwh | 89,523,000 | 14,013,000 |
| 13 | Cost of Plant | | |
| 14 | Land and Land Rights | 0 | 512,946 |
| 15 | Structures and Improvements | 1,696,549 | 632,785 |
| 16 | Reservoirs, Dams, and Waterways | 5,616,215 | 5,575,932 |
| 17 | Equipment Costs | 1,341,642 | 2,237,155 |
| 18 | Roads, Railroads, and Bridges | 16,778 | 0 |
| 19 | Asset Retirement Costs | 0 | 0 |
| 20 | TOTAL cost (Total of 14 thru 19) | 8,671,184 | 8,958,818 |
| 21 | Cost per KW of Installed Capacity (line 20 / 5) | 481.7324 | 639.9156 |
| 22 | Production Expenses | | |
| 23 | Operation Supervision and Engineering | 140,992 | 74,041 |
| 24 | Water for Power | 15,022 | 877 |
| 25 | Hydraulic Expenses | 75,945 | 40,543 |
| 26 | Electric Expenses | 0 | 0 |
| 27 | Misc Hydraulic Power Generation Expenses | 314,954 | 408,309 |
| 28 | Rents | 3,149 | -94 |
| 29 | Maintenance Supervision and Engineering | 0 | 0 |
| 30 | Maintenance of Structures | 22,596 | 1,170 |
| 31 | Maintenance of Reservoirs, Dams, and Waterways | 27,486 | 5,449 |
| 32 | Maintenance of Electric Plant | 37,251 | 49,880 |
| 33 | Maintenance of Misc Hydraulic Plant | 56,518 | 26,027 |
| 34 | Total Production Expenses (total 23 thru 33) | 693,913 | 606,202 |
| 35 | Expenses per net KWh | 0.0078 | 0.0433 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

| FERC Licensed Project No. 1927<br>Plant Name: Soda Springs<br>(d) | FERC Licensed Project No. 2111<br>Plant Name: Swift No. 1<br>(e) | FERC Licensed Project No. 2071<br>Plant Name: Yale<br>(f) | Line No. |
|---|---|---|---|
| | | | |
| | | | |
| Storage (Re-Reg) | Storage | Storage | 1 |
| Outdoor | Conventional | Conventional | 2 |
| 1952 | 1958 | 1953 | 3 |
| 1952 | 1958 | 1953 | 4 |
| 11.00 | 240.00 | 134.00 | 5 |
| 12 | 241 | 163 | 6 |
| 8,639 | 5,385 | 5,635 | 7 |
| | | | 8 |
| 12 | 264 | 164 | 9 |
| 12 | 264 | 164 | 10 |
| 1 | 2 | 2 | 11 |
| 56,787,000 | 593,027,000 | 539,777,000 | 12 |
| | | | 13 |
| 0 | 7,813,808 | 2,776,917 | 14 |
| 992,188 | 6,739,442 | 6,690,408 | 15 |
| 12,940,250 | 37,681,672 | 26,569,133 | 16 |
| 2,190,182 | 15,863,441 | 14,771,180 | 17 |
| 56,124 | 395,145 | 1,395,512 | 18 |
| 0 | 0 | 0 | 19 |
| 16,178,744 | 68,493,508 | 52,203,150 | 20 |
| 1,470.7949 | 285.3896 | 389.5757 | 21 |
| | | | 22 |
| 116,404 | 1,894,038 | 1,054,934 | 23 |
| 9,180 | 50,461 | 28,174 | 24 |
| 46,411 | 1,401,714 | 687,448 | 25 |
| 0 | 0 | 0 | 26 |
| 287,178 | 1,349,269 | 912,601 | 27 |
| 1,924 | 90,487 | 2,759 | 28 |
| 0 | 0 | 0 | 29 |
| 34,680 | 19,588 | 13,123 | 30 |
| 41,499 | 9,206 | 31,211 | 31 |
| 10,030 | 172,917 | 71,085 | 32 |
| 34,787 | 209,628 | 129,332 | 33 |
| 582,093 | 5,197,308 | 2,930,667 | 34 |
| 0.0103 | 0.0088 | 0.0054 | 35 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

| Line No. | Item<br>(a) | FERC Licensed Project No. 0<br>Plant Name: Olmsted<br>(b) | FERC Licensed Project No. 0<br>Plant Name:<br>(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 | 6,332 | 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 | 18,229,000 | 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 | 59,738 | 0 |
| 24 | Water for Power | 645 | 0 |
| 25 | Hydraulic Expenses | 26,617 | 0 |
| 26 | Electric Expenses | 0 | 0 |
| 27 | Misc Hydraulic Power Generation Expenses | 316,115 | 0 |
| 28 | Rents | -22 | 0 |
| 29 | Maintenance Supervision and Engineering | 0 | 0 |
| 30 | Maintenance of Structures | 1,451 | 0 |
| 31 | Maintenance of Reservoirs, Dams, and Waterways | 13,162 | 0 |
| 32 | Maintenance of Electric Plant | 63,246 | 0 |
| 33 | Maintenance of Misc Hydraulic Plant | 91,856 | 0 |
| 34 | Total Production Expenses (total 23 thru 33) | 572,808 | 0 |
| 35 | Expenses per net KWh | 0.0314 | 0.0000 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

| FERC Licensed Project No. 0<br>Plant Name:<br>(d) | FERC Licensed Project No. 0<br>Plant Name:<br>(e) | FERC Licensed Project No. 0<br>Plant Name:<br>(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 |

***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***

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, 2004 was $67,519,056: Lemolo 1, Lemolo 2, Clearwater 1, Clearwater 2, Toketee, Fish Creek, Soda Springs, Slide Creek and the North Umpqua Common Plant.

***Schedule Page: 406 Line No.: -1 Column: e***

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, 2004 was $67,519,056: Lemolo 1, Lemolo 2, Clearwater 1, Clearwater 2, Toketee, Fish Creek, Soda Springs, Slide Creek and the North Umpqua Common Plant.

***Schedule Page: 406 Line No.: -1 Column: f***

Costs reported for this plant do not include significant intangible costs due to relicensing which are charged to FERC account 302 and are not reported on this page. The net book value for relicensing at December 31, 2003 was $1,473,452.

***Schedule Page: 406 Line No.: 1 Column: b***

Pondage for peaking - storage, Upper Klamath Lake

***Schedule Page: 406 Line No.: 1 Column: d***

Forebay for peaking.

***Schedule Page: 406 Line No.: 1 Column: e***

Forebay for peaking.

***Schedule Page: 406.1 Line No.: -1 Column: b***

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, 2004 was $67,519,056: Lemolo 1, Lemolo 2, Clearwater 1, Clearwater 2, Toketee, Fish Creek, Soda Springs, Slide Creek and the North Umpqua Common Plant.

***Schedule Page: 406.1 Line No.: -1 Column: c***

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, 2004 was $16,940,164: Grace, Cove, Oneida and Soda.

***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***

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, 2004 was $67,519,056: Lemolo 1, Lemolo 2, Clearwater 1, Clearwater 2, Toketee, Fish Creek, Soda Springs, Slide Creek and the North Umpqua Common Plant.

***Schedule Page: 406.1 Line No.: 1 Column: b***

Forebay for peaking.

***Schedule Page: 406.1 Line No.: 1 Column: d***

Storage for regulation.

**Schedule Page: 406.1 Line No.: 1 Column: e**

Pondage for peaking - storage, Upper Klamath Lake.

**Schedule Page: 406.1 Line No.: 1 Column: f**

Storage, Lemolo Lake.

**Schedule Page: 406.2 Line No.: -1 Column: b**

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, 2004 was $67,519,056: 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**

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, 2004 was $67,519,056: 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: e**

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, 2004 was $16,940,164: Grace, Cove, Oneida and Soda.

**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**

Storage, Lemolo Lake.

**Schedule Page: 406.2 Line No.: 1 Column: d**

Pondage for peaking - storage, Lemolo Lake.

**Schedule Page: 406.2 Line No.: 1 Column: f**

Forebay for peaking.

**Schedule Page: 406.3 Line No.: -1 Column: b**

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, 2004 was $67,519,056: Lemolo 1, Lemolo 2, Clearwater 1, Clearwater 2, Toketee, Fish Creek, Soda Springs, Slide Creek and the North Umpqua Common Plant.

**Schedule Page: 406.3 Line No.: -1 Column: c**

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, 2004 was $16,940,164: Grace, Cove, Oneida and Soda.

**Schedule Page: 406.3 Line No.: -1 Column: d**

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, 2004 was $67,519,056: Lemolo 1, Lemolo 2, Clearwater 1, Clearwater 2, Toketee, Fish Creek, Soda Springs, Slide Creek and the North Umpqua Common Plant.

**Schedule Page: 406.3 Line No.: -1 Column: e**

**Swift #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 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 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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(Next Page is 410)

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## GENERATING PLANT STATISTICS (Small Plants)

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

| Line No. | Name of Plant (a) | Year Orig. Const. (b) | Installed Capacity Name Plate Rating (In MW) (c) | Net Peak Demand MW (60 min.) (d) | Net Generation Excluding Plant Use (e) | Cost of Plant (f) |
|---|---|---|---|---|---|---|
| 1 | Hydroelectric : Licensed Proj. No. | | | | | |
| 2 | Ashton 2381 | 1917 | 6.85 | 6.6 | 32,051 | 8,820,231 |
| 3 | Bend | 1913 | 1.11 | 1.0 | 2,917 | 930,840 |
| 4 | Big Fork 2652 | 1910 | 4.15 | 4.6 | 27,562 | 7,135,399 |
| 5 | Cline Falls | 1913 | 1.00 | | | 338,868 |
| 6 | Condit 2342 | 1913 | 13.70 | 15.0 | 86,883 | 6,932,747 |
| 7 | Eagle Point | 1957 | 2.81 | 2.8 | 17,350 | 1,791,404 |
| 8 | Eastside 2082 | 1924 | 3.20 | 3.0 | 5,350 | 1,976,602 |
| 9 | Fall Creek 2082 | 1903 | 2.20 | 2.0 | 13,723 | 1,215,360 |
| 10 | Fountain Green | 1922 | 0.16 | 0.1 | 380 | 464,080 |
| 11 | Granite | 1896 | 2.00 | 1.2 | 6,341 | 4,957,527 |
| 12 | Gunlock | 1917 | 0.75 | 0.6 | 915 | 635,418 |
| 13 | Last Chance | 1983 | 1.73 | 0.7 | 2,488 | 2,900,421 |
| 14 | Paris | 1910 | 0.72 | 0.7 | 2,294 | 327,935 |
| 15 | Pioneer 2722 | 1897 | 5.00 | 4.0 | 14,734 | 11,089,922 |
| 16 | Powerdale 2659 | 1923 | 6.00 | | | 725,996 |
| 17 | Prospect No. 1 2630 | 1912 | 3.76 | 4.6 | 33,064 | 969,670 |
| 18 | Prospect No. 3 2337 | 1932 | 7.20 | 7.7 | 41,051 | 6,955,542 |
| 19 | Prospect No. 4 2630 | 1944 | 1.00 | 0.9 | 6,034 | 356,987 |
| 20 | Sand Cove | 1926 | 0.80 | 0.5 | 843 | 860,634 |
| 21 | Snake Creek | 1910 | 1.18 | 1.0 | 3,406 | 950,757 |
| 22 | Stairs 597 | 1895 | 1.00 | 1.2 | 5,921 | 1,609,662 |
| 23 | St. Anthony 2381 | 1915 | 0.50 | | | 1,337,279 |
| 24 | Veyo | 1920 | 0.50 | 0.3 | 727 | 748,404 |
| 25 | Viva Naughton | 1986 | 0.74 | 0.6 | 717 | 1,169,596 |
| 26 | Wallowa Falls 308 | 1921 | 1.10 | 1.0 | 6,819 | 2,821,770 |
| 27 | Weber 1744 | 1911 | 3.85 | 2.0 | 16,470 | 2,791,674 |
| 28 | West Side 2082 | 1908 | 0.60 | 0.6 | 719 | 372,835 |
| 29 | Keno Regulating Dam 2082 | | | | | 7,497,523 |
| 30 | Upper Klamath Lake 2082 | | | | | 5,062,891 |
| 31 | North Umpqua 1927 | | | | | 13,800,218 |
| 32 | | | | | | |
| 33 | Pumping Plant: | | | | | |
| 34 | Lifton | 1917 | -4.50 | -3.0 | -3,261 | 16,508,203 |
| 35 | | | | | | |
| 36 | Wind: | | | | | |
| 37 | Foote Creek | 1998 | 32.62 | 32.0 | 106,930 | 36,976,588 |
| 38 | Glenrock | 2008 | 99.00 | | | 199,426,199 |
| 39 | Goodnoe Hills | 2008 | 94.00 | 56.0 | 147,308 | 183,939,586 |
| 40 | Leaning Juniper 1 | 2006 | 100.50 | 100.5 | 312,614 | 172,416,795 |
| 41 | Marengo | 2007 | 140.40 | 140.0 | 400,245 | 238,896,531 |
| 42 | Marengo II | 2008 | 70.20 | 70.0 | 78,457 | 125,100,049 |
| 43 | Seven Mile Hill | 2008 | 99.00 | | | 192,904,480 |
| 44 | Seven Mile Hill II | 2008 | 19.50 | | | 41,391,245 |
| 45 | | | | | | |
| 46 | | | | | | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

GENERATING PLANT STATISTICS (Small Plants) (Continued)

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

| Plant Cost (Incl Asset Retire. Costs) Per MW (g) | Operation Exc'l. Fuel (h) | Production Expenses Fuel (i) | Production Expenses Maintenance (j) | Kind of Fuel (k) | Fuel Costs (in cents (per Million Btu) (l) | Line No. |
|---|---|---|---|---|---|---|
| | | | | | | 1 |
| 1,287,625 | 407,176 | | 86,715 | Water | | 2 |
| 838,595 | 83,025 | | 83,706 | Water | | 3 |
| 1,719,373 | 356,341 | | 119,167 | Water | | 4 |
| 338,868 | 5,145 | | 780 | Water | | 5 |
| 506,040 | 402,065 | | 59,390 | Water | | 6 |
| 637,510 | 242,493 | | 51,275 | Water | | 7 |
| 617,688 | 142,213 | | 47,054 | Water | | 8 |
| 552,436 | 87,709 | | 49,968 | Water | | 9 |
| 2,900,500 | 19,998 | | 26,377 | Water | | 10 |
| 2,478,764 | 116,639 | | 44,664 | Water | | 11 |
| 847,224 | 63,219 | | 49,216 | Water | | 12 |
| 1,676,544 | 134,876 | | 86,796 | Water | | 13 |
| 455,465 | 48,515 | | 38,861 | Water | | 14 |
| 2,217,984 | 280,862 | | 73,927 | Water | | 15 |
| 120,999 | 203,399 | | 11,385 | Water | | 16 |
| 257,891 | 198,965 | | 88,826 | Water | | 17 |
| 966,048 | 339,131 | | 109,291 | Water | | 18 |
| 356,987 | 79,334 | | 19,898 | Water | | 19 |
| 1,075,793 | 59,178 | | 94,455 | Water | | 20 |
| 805,726 | 87,182 | | 19,780 | Water | | 21 |
| 1,609,662 | 99,926 | | 14,442 | Water | | 22 |
| 2,674,558 | 64,579 | | 5,112 | Water | | 23 |
| 1,496,808 | 84,060 | | 110,791 | Water | | 24 |
| 1,580,535 | 21,918 | | 14,062 | Water | | 25 |
| 2,565,245 | 84,084 | | 386 | Water | | 26 |
| 725,110 | 208,250 | | 51,910 | Water | | 27 |
| 621,392 | 20,844 | | 18,749 | Water | | 28 |
| | 4,584 | | 17,274 | | | 29 |
| | 210,717 | | 39,412 | | | 30 |
| | | | | | | 31 |
| | | | | | | 32 |
| | | | | | | 33 |
| -3,668,490 | 236,119 | | 81,447 | Water | | 34 |
| | | | | | | 35 |
| | | | | | | 36 |
| 1,133,556 | 2,071,010 | | | Wind | | 37 |
| 2,014,406 | 91,715 | | | Wind | | 38 |
| 1,881,542 | -240,515 | | | Wind | | 39 |
| 1,715,590 | 3,576,738 | | | Wind | | 40 |
| 1,701,542 | 4,396,346 | | | Wind | | 41 |
| 1,782,052 | 1,039,654 | | | Wind | | 42 |
| 1,948,530 | 52,549 | | | Wind | | 43 |
| 2,122,628 | 17,869 | | | Wind | | 44 |
| | | | | | | 45 |
| | | | | | | 46 |

***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***

**Ashton**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

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, 2008 was $356,483.

***Schedule Page: 410 Line No.: 3 Column: a***

**Bend**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

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, 2008 was $230,098.

***Schedule Page: 410 Line No.: 4 Column: a***

**Big Fork**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

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, 2008 was $560,499.

***Schedule Page: 410 Line No.: 5 Column: a***

**Cline Falls**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

***Schedule Page: 410 Line No.: 6 Column: a***

**Condit**

In September 1999, a settlement agreement to remove the 14-MW Condit hydroelectric facility 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 would not begin until October 2008, with 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. Given the ongoing permitting process and the time needed for system removal and to evaluate impacts on natural resources, decommissioning is now expected to begin in October 2010. In March 2008, the United States Army Corps of Engineers requested PacifiCorp complete an additional study of expected decommissioning impacts on aquatic resources. The study work is complete and results have been provided to the United States Army Corps of Engineers and the Washington Department of Ecology. Absent further information requests, the Washington Department of Ecology is expected to complete the Clean Water Act 401 certification process during 2009. Remaining permitting includes a 404 permit from the United States Army Corps of Engineers and a surrender order from the FERC.

***Schedule Page: 410 Line No.: 7 Column: a***

**Eagle Point**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

***Schedule Page: 410 Line No.: 8 Column: a***

**Eastside**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

***Schedule Page: 410 Line No.: 9 Column: a***

**Fall Creek**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

***Schedule Page: 410 Line No.: 10 Column: a***

**Fountain Green**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

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, 2008 was $5,182.

***Schedule Page: 410 Line No.: 11 Column: a***

**Granite**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

***Schedule Page: 410 Line No.: 12 Column: a***

**Gunlock**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

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, 2008 was $48,556.

***Schedule Page: 410 Line No.: 13 Column: a***

**Last Chance**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

***Schedule Page: 410 Line No.: 14 Column: a***

**Paris**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

***Schedule Page: 410 Line No.: 15 Column: a***

**Pioneer**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

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, 2008 was $120,435.

***Schedule Page: 410 Line No.: 16 Column: a***

**Powerdale**

In June 2003, PacifiCorp entered into a settlement agreement to remove the 6-MW 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 system features, which is subject to the FERC and other regulatory approvals, is projected to cost $6 million, excluding inflation.

Plant shut down and 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 plant; however, removal is still scheduled for 2010. Also in February 2007, PacifiCorp submitted a request to the FERC to allow PacifiCorp to defer the remaining net book value and any additional removal costs of this system 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 regulatory commissions to defer and recover these costs.

***Schedule Page: 410 Line No.: 17 Column: a***

**Prospect 1**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

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 units 1, 2, and 4 on December 31, 2008 was $6,631,099.

***Schedule Page: 410 Line No.: 18 Column: a***

**Prospect 3**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

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, 2008 was $98,015.

***Schedule Page: 410 Line No.: 19 Column: a***

**Prospect 4**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

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 units 1, 2, and 4 on December 31, 2008 was $6,631,099.

***Schedule Page: 410 Line No.: 20 Column: a***

**Sand Cove**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

***Schedule Page: 410 Line No.: 21 Column: a***

**Snake Creek**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

***Schedule Page: 410 Line No.: 22 Column: a***

**Stairs**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

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, 2008 was $94,537.

**Schedule Page: 410 Line No.: 23 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 (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

**Schedule Page: 410 Line No.: 24 Column: a**

**Veyo**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

**Schedule Page: 410 Line No.: 25 Column: a**

**Viva Naughton**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

**Schedule Page: 410 Line No.: 26 Column: a**

**Wallowa Falls**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

**Schedule Page: 410 Line No.: 27 Column: a**

**Weber**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

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, 2008 was $352,427.

**Schedule Page: 410 Line No.: 28 Column: a**

**West Side**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

**Schedule Page: 410 Line No.: 29 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.: 30 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.: 31 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, 2008 was $68,917,344: 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.: 37 Column: a**

**Foote Creek**

The Foote 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 (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

***Schedule Page: 410 Line No.: 38 Column: a***

**Glenrock**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

***Schedule Page: 410 Line No.: 39 Column: a***

**Goodnoe Hills**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

***Schedule Page: 410 Line No.: 39 Column: h***

The credit balance for the Goodnoe Hills wind plant includes both funds received from the Energy Trust of Oregon to offset operations and maintenance costs and credits from the BPA for renewable energy.

***Schedule Page: 410 Line No.: 40 Column: a***

**Leaning Juniper #1**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

***Schedule Page: 410 Line No.: 41 Column: a***

**Marengo I**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

***Schedule Page: 410 Line No.: 42 Column: a***

**Marengo II**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

***Schedule Page: 410 Line No.: 43 Column: a***

**Seven Mile Hill**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

***Schedule Page: 410 Line No.: 44 Column: a***

**Seven Mile Hill II**

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

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(Next Page is 422)

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## TRANSMISSION LINE STATISTICS

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

| Line No. | DESIGNATION | | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) | | Type of Supporting Structure | LENGTH (Pole miles) (In the case of underground lines report circuit miles) | | Number Of Circuits |
|---|---|---|---|---|---|---|---|---|
| | From (a) | To (b) | Operating (c) | Designed (d) | (e) | On Structure of Line Designated (f) | On Structures of Another Line (g) | (h) |
| 1 | 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 | | | | | 1,211.00 | | 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 | 94.00 | | 2 |
| 18 | Spanish Fork Sub., UT | Camp Williams Sub., UT | 345.00 | 345.00 | Steel - SP | 35.00 | | 1 |
| 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 | 32.00 | | 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 | 22.00 | | 2 |
| 25 | Terminal Substation, UT | Camp Williams Sub., UT | 345.00 | 345.00 | Steel - D | 52.00 | | 2 |
| 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 | Pinto Substation, 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 | 116.00 | | 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 | 16,292.00 | 150.00 | 220 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original (2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## TRANSMISSION LINE STATISTICS (Continued)

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

| Size of Conductor and Material (i) | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j) | Construction and Other Costs (k) | Total Cost (l) | EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | Line No. |
|---|---|---|---|---|---|---|---|---|
| 2-1852 ACSR | 134,356 | 5,551,720 | 5,686,076 | | | | | 1 |
| 3-1272 ACSR | 3,086,400 | 151,289,387 | 154,375,787 | | | | | 2 |
| 3-1272 ACSR | 2,907,175 | 37,830,903 | 40,738,078 | | | | | 3 |
| 3-1272 ACSR | 1,468,204 | 19,534,183 | 21,002,387 | | | | | 4 |
| 1272 ACSR | 9,230 | 1,460,042 | 1,469,272 | | | | | 5 |
| 3-1272 ACSR | 4,769,435 | 26,243,799 | 31,013,234 | | | | | 6 |
| 795 KCM ACSR | | 34,086 | 34,086 | | | | | 7 |
| 795 KCM ACSR | 219,555 | 5,424,681 | 5,644,236 | | | | | 8 |
| 795 KCM ACSR | 276,827 | 7,157,642 | 7,434,469 | | | | | 9 |
| 795 KCM ACSR | 419,697 | 6,587,899 | 7,007,596 | | | | | 10 |
| 795 KCM ACSR | 436,817 | 6,500,719 | 6,937,536 | | | | | 11 |
| | | | | | 1,054,883 | 130,930 | 1,185,813 | 12 |
| | | | | | | | | 13 |
| | 13,727,696 | 267,615,061 | 281,342,757 | | 1,054,883 | 130,930 | 1,185,813 | 14 |
| | | | | | | | | 15 |
| 954 | 5,229,653 | 35,379,459 | 40,609,112 | | | | | 16 |
| 1272 | 9,289,095 | 22,142,789 | 31,431,884 | | | | | 17 |
| 1272 | 5,503,014 | 10,158,595 | 15,661,609 | | | | | 18 |
| 954 | 343,174 | 20,080,785 | 20,423,959 | | | | | 19 |
| 954 | 977,245 | 17,683,063 | 18,660,308 | | | | | 20 |
| 1272 | 2,546,471 | 7,455,160 | 10,001,631 | | | | | 21 |
| 954 | 320,316 | 13,619,157 | 13,939,473 | | | | | 22 |
| 954 | 510,490 | 25,192,646 | 25,703,136 | | | | | 23 |
| 1272 | 482,188 | 3,895,713 | 4,377,901 | | | | | 24 |
| 1272 | 4,299,093 | 7,962,490 | 12,261,583 | | | | | 25 |
| 954 | 926,251 | 27,920,818 | 28,847,069 | | | | | 26 |
| 954 | 2,320,872 | 50,681,886 | 53,002,758 | | | | | 27 |
| 954 | 56,050 | 13,605,494 | 13,661,544 | | | | | 28 |
| 795 | 313,477 | 2,576,297 | 2,889,774 | | | | | 29 |
| 954 | 117,662 | 2,886,582 | 3,004,244 | | | | | 30 |
| 795 | 893,965 | 19,899,214 | 20,793,179 | | | | | 31 |
| 795 | | | | | | | | 32 |
| 795 | 179,502 | 16,634,715 | 16,814,217 | | | | | 33 |
| 1272 | 1,128,222 | 26,078,139 | 27,206,361 | | | | | 34 |
| 1272 | 1,099,796 | 27,392,214 | 28,492,010 | | | | | 35 |
| | 87,473,552 | 1,741,496,237 | 1,828,969,789 | 93,337 | 16,204,998 | 803,249 | 17,101,584 | 36 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original (2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## TRANSMISSION LINE STATISTICS

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

| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | Currant Creek Swtchrd, UT | Mona Substation, UT | 345.00 | 345.00 | Steel - SP | 1.00 | | 1 |
| 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 | | | | | 2,052.00 | 42.00 | 26 |
| 6 | | | | | | | | |
| 7 | Fairview, OR | Isthmus, OR | 230.00 | 230.00 | H Frame Wood | 12.00 | | 1 |
| 8 | Antelope Sub., ID | Lost River, 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 | Dalreed 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 | | 1 |
| 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 | 16,292.00 | 150.00 | 220 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## TRANSMISSION LINE STATISTICS (Continued)

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

| Size of Conductor and Material (i) | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j) | Construction and Other Costs (k) | Total Cost (l) | EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | Line No. |
|---|---|---|---|---|---|---|---|---|
| | | 1,178,479 | 1,178,479 | | | | | 1 |
| 1272 | | 9,573,299 | 9,573,299 | | | | | 2 |
| | | | | | 1,824,214 | 133,200 | 1,957,414 | 3 |
| | | | | | | | | 4 |
| | 36,536,536 | 361,996,994 | 398,533,530 | | 1,824,214 | 133,200 | 1,957,414 | 5 |
| | | | | | | | | 6 |
| 954 | 285,322 | 1,777,619 | 2,062,941 | | | | | 7 |
| 795 | 12,929 | 1,143,095 | 1,156,024 | | | | | 8 |
| 1272 | 64,394 | 11,450,460 | 11,514,854 | | | | | 9 |
| 1272 | 351,982 | 2,207,541 | 2,559,523 | | | | | 10 |
| 1272 | 485,896 | 4,890,778 | 5,376,674 | | | | | 11 |
| 954 | 1,428,247 | 14,172,177 | 15,600,424 | | | | | 12 |
| 954 | | 439,677 | 439,677 | | | | | 13 |
| 954 | 363,717 | 577,809 | 941,526 | | | | | 14 |
| 1272 | 220,967 | 3,378,568 | 3,599,535 | | | | | 15 |
| 795 | | 30,397 | 30,397 | | | | | 16 |
| 795 | 468,992 | 7,660,343 | 8,129,335 | | | | | 17 |
| | 39,971 | 1,500,885 | 1,540,856 | | | | | 18 |
| 795 | | | | | | | | 19 |
| 795 | 473,366 | 4,066,461 | 4,539,827 | | | | | 20 |
| 795 | 439,563 | 3,160,501 | 3,600,064 | | | | | 21 |
| 795 | 173,608 | 5,665,174 | 5,838,782 | | | | | 22 |
| 1272 | 115,448 | 1,798,928 | 1,914,376 | | | | | 23 |
| 954 | 191,124 | 5,220,765 | 5,411,889 | | | | | 24 |
| 1272 | 379,961 | 11,626,021 | 12,005,982 | | | | | 25 |
| 1272 | | 502,476 | 502,476 | | | | | 26 |
| 795 | 41,499 | 4,375,777 | 4,417,276 | | | | | 27 |
| 795 | | | | | | | | 28 |
| 1272 | 5,103 | 2,429,200 | 2,434,303 | | | | | 29 |
| 795 | 72,118 | 2,193,580 | 2,265,698 | | | | | 30 |
| 795 | 426,126 | 4,485,653 | 4,911,779 | | | | | 31 |
| 954 | 22,643 | 4,609,030 | 4,631,673 | | | | | 32 |
| 954 | 165,054 | 1,299,642 | 1,464,696 | | | | | 33 |
| 954 | 181,047 | 1,520,220 | 1,701,267 | | | | | 34 |
| 1272 | 736,030 | 5,273,708 | 6,009,738 | | | | | 35 |
| | 87,473,552 | 1,741,496,237 | 1,828,969,789 | 93,337 | 16,204,998 | 803,249 | 17,101,584 | 36 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original (2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## TRANSMISSION LINE STATISTICS

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

| Line No. | DESIGNATION | | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) | | Type of Supporting Structure | LENGTH (Pole miles) (In the case of underground lines report circuit miles) | | Number Of Circuits |
|---|---|---|---|---|---|---|---|---|
| | From (a) | To (b) | Operating (c) | Designed (d) | (e) | On Structure of Line Designated (f) | On Structures of Another Line (g) | (h) |
| 1 | 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 | | 1 |
| 14 | Meridian Sub, OR | Lone Pine Sub, OR | 230.00 | 230.00 | Steel - DC | | 5.00 | 1 |
| 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 | | | 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 | | 1 |
| 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 | 16,292.00 | 150.00 | 220 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## TRANSMISSION LINE STATISTICS (Continued)

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

| Size of Conductor and Material (i) | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j) | Construction and Other Costs (k) | Total Cost (l) | EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | Line No. |
|---|---|---|---|---|---|---|---|---|
| 1272 | | 1,716,429 | 1,716,429 | | | | | 1 |
| 954 | 170,967 | 5,949,461 | 6,120,428 | | | | | 2 |
| 1272 | 572,459 | 10,534,187 | 11,106,646 | | | | | 3 |
| 954 | 56,498 | 2,993,309 | 3,049,807 | | | | | 4 |
| 954 | 569 | 27,377 | 27,946 | | | | | 5 |
| 954 | 1,293 | 326,731 | 328,024 | | | | | 6 |
| 954 | 103,532 | 2,530,686 | 2,634,218 | | | | | 7 |
| 1272 | 172,451 | 1,705,145 | 1,877,596 | | | | | 8 |
| 1272 | 363,082 | 5,901,659 | 6,264,741 | | | | | 9 |
| 954 | 235,532 | 2,387,909 | 2,623,441 | | | | | 10 |
| 1780 | 207,123 | 2,443,035 | 2,650,158 | | | | | 11 |
| 556.5 | 169 | 1,514,165 | 1,514,334 | | | | | 12 |
| 1272 | | 2,003,740 | 2,003,740 | | | | | 13 |
| | | | | | | | | 14 |
| 1272 | | 2,223,562 | 2,223,562 | | | | | 15 |
| 1272 | 89,845 | 5,940,815 | 6,030,660 | | | | | 16 |
| 1272 | | | | | | | | 17 |
| 795 | 14,928 | 1,193,336 | 1,208,264 | | | | | 18 |
| 1271 | 130,197 | 10,011,766 | 10,141,963 | | | | | 19 |
| 1271 | 52,906 | 3,415,079 | 3,467,985 | | | | | 20 |
| 954 | 31,859 | 3,134,024 | 3,165,883 | | | | | 21 |
| 1272 | 57,112 | 2,100,040 | 2,157,152 | | | | | 22 |
| 954 | 67,857 | 5,214,009 | 5,281,866 | | | | | 23 |
| 1272 | 58,102 | 12,140,358 | 12,198,460 | | | | | 24 |
| 1272 | 33,008 | 2,514,280 | 2,547,288 | | | | | 25 |
| 1271 | 48,281 | 3,934,319 | 3,982,600 | | | | | 26 |
| 1272 | 30,769 | 2,662,969 | 2,693,738 | | | | | 27 |
| 1272 | 12 | 579,142 | 579,154 | | | | | 28 |
| 1272 | 361,351 | 4,350,959 | 4,712,310 | | | | | 29 |
| 1272 | 4,800 | 140,313 | 145,113 | | | | | 30 |
| 1272 | | 130,166 | 130,166 | | | | | 31 |
| 1272 | 294,290 | 6,158,106 | 6,452,396 | | | | | 32 |
| 1272 | | 15,274 | 15,274 | | | | | 33 |
| 1272 | 3,967 | 441,494 | 445,461 | | | | | 34 |
| 1272 | | 886,493 | 886,493 | | | | | 35 |
| | 87,473,552 | 1,741,496,237 | 1,828,969,789 | 93,337 | 16,204,998 | 803,249 | 17,101,584 | 36 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## TRANSMISSION LINE STATISTICS

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

| Line No. | DESIGNATION | | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) | | Type of Supporting Structure | LENGTH (Pole miles) (In the case of underground lines report circuit miles) | | Number Of Circuits |
|---|---|---|---|---|---|---|---|---|
| | From (a) | To (b) | Operating (c) | Designed (d) | (e) | On Structure of Line Designated (f) | On Structures of Another Line (g) | (h) |
| 1 | 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 | | 1 |
| 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 | Craven Creek Substation, WY | Pioneer Substation, WY | 230.00 | 230.00 | Wood - H | 3.00 | | 1 |
| 15 | Chappel Creek Sub., WY | Jonah Field, Substation, WY | 230.00 | 230.00 | Wood - H | 35.00 | | 1 |
| 16 | Marengo Wind, WA | Tablot Substation, WA | 230.00 | 230.00 | Wood - H | 4.00 | | 1 |
| 17 | 230 kV expenses | | | | | | | |
| 18 | | | | | | | | |
| 19 | Subtotal 230 kV | | | | | 3,347.00 | 5.00 | 80 |
| 20 | | | | | | | | |
| 21 | Montana-Idaho State line | Grace Plant, ID | 161.00 | 161.00 | Wood - H | 57.00 | 90.00 | 1 |
| 22 | Goshen Substation, ID | Rigby Substation, ID | 161.00 | 161.00 | Wood - H | 61.00 | | 1 |
| 23 | Goshen Substation, ID | Antelope Substation, ID | 161.00 | 161.00 | Wood - H | 45.00 | | 1 |
| 24 | Goshen Substation, ID | Sugar Mill Substation, ID | 161.00 | 161.00 | Wood - SP | 17.00 | | 1 |
| 25 | Sugar Mill Sub., ID | Rigby Substation, ID | 161.00 | 161.00 | Wood - SP | 17.00 | | 1 |
| 26 | Goshen Substation, ID | Bonneville Sub., ID | 161.00 | 161.00 | Wood - SP-H | 23.00 | | 1 |
| 27 | Billings, MT | Yellowtail, MT | 161.00 | 161.00 | H Frame Wood | 46.00 | | 1 |
| 28 | Big Grassy Sub., ID | Idaho Power Line, ID | 161.00 | 161.00 | Wood - H | 1.00 | | 1 |
| 29 | Rigby Sub., ID | Jefferson Roberts, ID | 161.00 | 161.00 | Wood - SP | 18.00 | | 1 |
| 30 | 161 kV expenses | | | | | | | |
| 31 | | | | | | | | |
| 32 | Subtotal 161 kV | | | | | 285.00 | 90.00 | 9 |
| 33 | | | | | | | | |
| 34 | Naughton Plant, WY | Evanston Substation, WY | 138.00 | 138.00 | Wood - H | 67.00 | | 1 |
| 35 | Evanston Substation, WY | Anschutz Substation, WY | 138.00 | 138.00 | Wood - H | 6.00 | | 1 |
| 36 | | | | | TOTAL | 16,292.00 | 150.00 | 220 |

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) Land (j) | Construction and Other Costs (k) | Total Cost (l) | EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | Line No. |
|---|---|---|---|---|---|---|---|---|
| 1272 | | 43,839 | 43,839 | | | | | 1 |
| 1272 | | | | | | | | 2 |
| 1272 | | 2,576,371 | 2,576,371 | | | | | 3 |
| 1272 | | 2,720,479 | 2,720,479 | | | | | 4 |
| 1272 | | 170,295 | 170,295 | | | | | 5 |
| 1272 | 4,591 | 9,771,492 | 9,776,083 | | | | | 6 |
| 1272 | | 9,565,742 | 9,565,742 | | | | | 7 |
| 1272 | 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 |
| 1272 ACSR | | 837,446 | 837,446 | | | | | 14 |
| 1272 ACSR | | 11,524,191 | 11,524,191 | | | | | 15 |
| 795 KCM ACSR | | 1,827,482 | 1,827,482 | | | | | 16 |
| | | | | 4,927 | 3,241,691 | 140,659 | 3,387,277 | 17 |
| | | | | | | | | 18 |
| | 10,333,379 | 271,190,396 | 281,523,775 | 4,927 | 3,241,691 | 140,659 | 3,387,277 | 19 |
| | | | | | | | | 20 |
| 397.5 | 18,978 | 1,758,724 | 1,777,702 | | | | | 21 |
| 397.5 | 27,520 | 822,583 | 850,103 | | | | | 22 |
| 397.5 | 8,857 | 2,688,332 | 2,697,189 | | | | | 23 |
| 397.5 | 48,227 | 1,473,083 | 1,521,310 | | | | | 24 |
| 397.5 | 27,536 | 1,210,177 | 1,237,713 | | | | | 25 |
| 954 | 362,279 | 2,845,761 | 3,208,040 | | | | | 26 |
| 556.5 | | 2,274,333 | 2,274,333 | | | | | 27 |
| 556.5 | | 12,194 | 12,194 | | | | | 28 |
| 556.5 | 76,306 | 1,273,485 | 1,349,791 | | | | | 29 |
| | | | | | 207,255 | 1,862 | 209,117 | 30 |
| | | | | | | | | 31 |
| | 569,703 | 14,358,672 | 14,928,375 | | 207,255 | 1,862 | 209,117 | 32 |
| | | | | | | | | 33 |
| 795 | 146,645 | 4,056,397 | 4,203,042 | | | | | 34 |
| 795 | 129,129 | 498,590 | 627,719 | | | | | 35 |
| | 87,473,552 | 1,741,496,237 | 1,828,969,789 | 93,337 | 16,204,998 | 803,249 | 17,101,584 | 36 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## TRANSMISSION LINE STATISTICS

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

| Line No. | DESIGNATION | | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) | | Type of Supporting Structure | LENGTH (Pole miles) (In the case of underground lines report circuit miles) | | Number Of Circuits |
|---|---|---|---|---|---|---|---|---|
| | From (a) | To (b) | Operating (c) | Designed (d) | (e) | On Structure of Line Designated (f) | On Structures of Another Line (g) | (h) |
| 1 | Evanston Substation, WY | Anschutz Substation, WY | 138.00 | 138.00 | Wood - H | 15.00 | | 1 |
| 2 | Naughton Plant, WY | Carter Creek Sub., WY | 138.00 | 138.00 | Wood - H | 36.00 | | 1 |
| 3 | Railroad Sub., WY | Carter Creek Sub., WY | 138.00 | 138.00 | Wood - H | 17.00 | | 1 |
| 4 | Painter Substation, WY | Natural Gas Sub., WY | 138.00 | 138.00 | Wood - H | 5.00 | | 1 |
| 5 | Grace Plant, ID | Termnl. Sub., UT (103-104) | 138.00 | 138.00 | Steel - S | 42.00 | | 2 |
| 6 | Grace Point, ID | Termnl. Sub., UT (103-104) | 138.00 | 138.00 | Wood - H | 211.00 | | 2 |
| 7 | Grace Plant, ID | Terminal Sub., UT (105) | 138.00 | 138.00 | Wood - H | 143.00 | | 2 |
| 8 | Grace Plant, ID | Soda Plant, ID | 138.00 | 138.00 | Wood - H | 8.00 | 4.00 | 2 |
| 9 | Oneida Plant, ID | Ovid Substation, ID | 138.00 | 138.00 | Wood - H | 23.00 | | 1 |
| 10 | Antelope Substation, ID | Scoville Sub., ID | 138.00 | 138.00 | Wood - H | 1.00 | | 1 |
| 11 | Soda Plant, Idaho | Monsanto Sub., ID | 138.00 | 138.00 | Wood - H | 14.00 | | 1 |
| 12 | Three Mile Knoll Sub., ID | Grace Plant, ID | 138.00 | 138.00 | Wood - H | 18.00 | | 1 |
| 13 | Three Mile Knoll Sub., ID | Becker Substation, ID | 138.00 | 138.00 | Wood - H | 4.00 | | 1 |
| 14 | Treasureton Sub., ID | Franklin Sub., ID | 138.00 | 138.00 | Wood - H & S | 10.00 | | 1 |
| 15 | Franklin Substation, ID | Smithfield Sub., UT | 138.00 | 138.00 | Wood - H | 25.00 | | 1 |
| 16 | Midvalley Substation, UT | Thirty South Sub., UT | 138.00 | 138.00 | Wood - H | 1.00 | | 1 |
| 17 | Angel Substation, UT | Smith's UT | 138.00 | 138.00 | Wood - H | 1.00 | | 1 |
| 18 | Terminal Substation, UT | 30 South Switch Rack, UT | 138.00 | 138.00 | Steel - S | 7.00 | | 1 |
| 19 | Jordan, UT | Terminal Substation, UT | 138.00 | 138.00 | Wood - H | 6.00 | | 1 |
| 20 | Wheelon Substation, UT | American Falls Sub., UT | 138.00 | 138.00 | Wood - H | 82.00 | | 1 |
| 21 | Cutler Plant, UT | Wheelon Substation, UT | 138.00 | 138.00 | Wood - H | 1.00 | | 1 |
| 22 | Terminal Substation, UT | Helper Substation, UT | 138.00 | 138.00 | Wood - H | 116.00 | | 1 |
| 23 | Hale Plant, UT | Nebo Substation, UT | 138.00 | 138.00 | Wood - H | 54.00 | | 1 |
| 24 | Carbon Plant, UT | Helper Substation, UT | 138.00 | 138.00 | Wood - H | 2.00 | | 1 |
| 25 | Terminal Substation, UT | Tooele Substation, UT | 138.00 | 138.00 | Wood - H | 42.00 | | 1 |
| 26 | Wheelon Substation, UT | Smithfield Sub., UT | 138.00 | 138.00 | Wood - H | 19.00 | 1.00 | 2 |
| 27 | Helper Substation, UT | Moab Substation, UT | 138.00 | 138.00 | Wood - H | 118.00 | | 1 |
| 28 | Ninetieth South Sub, UT | Carbon Plant, UT | 138.00 | 138.00 | Wood - H | 75.00 | | 2 |
| 29 | Terminal Substation, UT | Ninetieth South Sub, UT | 138.00 | 138.00 | Wood - H | 16.00 | | 2 |
| 30 | 30 South Switch Rack, UT | McClelland Sub., UT | 138.00 | 138.00 | Wood - SP | 6.00 | | 1 |
| 31 | Moab Substation, UT | Pinto Substation, UT | 138.00 | 138.00 | Wood - H | 68.00 | | 1 |
| 32 | Pinto Substation, UT | Abajo, UT | 138.00 | 138.00 | Wood - H | 45.00 | | 1 |
| 33 | Carbon Plant, UT | Ashley Substation, UT | 138.00 | 138.00 | Wood - H | 92.00 | | 1 |
| 34 | McClelland Sub., UT | Cottonwood Sub., UT | 138.00 | 138.00 | Wood - SP | 6.00 | | 1 |
| 35 | Ashley Substation, UT | Vernal Substation, UT | 138.00 | 138.00 | Wood - H | 12.00 | | 1 |
| 36 | | | | | TOTAL | 16,292.00 | 150.00 | 220 |

## 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 | 3,381 | 290,803 | 294,184 | | | | | 1 |
| 795 | 41,411 | 3,577,596 | 3,619,007 | | | | | 2 |
| 795 | 72,622 | 3,889,759 | 3,962,381 | | | | | 3 |
| 795 | -12,424 | -278,836 | -291,260 | | | | | 4 |
| 795 | 765,185 | 13,281,773 | 14,046,958 | | | | | 5 |
| 795 | | | | | | | | 6 |
| 250 | 132,960 | 16,104,165 | 16,237,125 | | | | | 7 |
| 795 | 3,290 | 226,715 | 230,005 | | | | | 8 |
| 336 | 4,817 | 942,031 | 946,848 | | | | | 9 |
| 397.5 | 149 | 41 | 190 | | | | | 10 |
| 397.5 | 2,555 | 295,902 | 298,457 | | | | | 11 |
| 795 | 306,339 | 420,886 | 727,225 | | | | | 12 |
| 397.5 | 14,424 | 145,941 | 160,365 | | | | | 13 |
| 795 | 39,101 | 540,247 | 579,348 | | | | | 14 |
| 397.5 | 47,613 | 1,093,808 | 1,141,421 | | | | | 15 |
| | | 192,647 | 192,647 | | | | | 16 |
| | | 20,229 | 20,229 | | | | | 17 |
| 500 | 1,837 | 1,256,746 | 1,258,583 | | | | | 18 |
| | 661,447 | 2,064,141 | 2,725,588 | | | | | 19 |
| 250 | 118,180 | 6,200,333 | 6,318,513 | | | | | 20 |
| 250 | | 69,072 | 69,072 | | | | | 21 |
| 250 | 458,799 | 11,901,681 | 12,360,480 | | | | | 22 |
| 397.5 | 27,545 | 4,628,063 | 4,655,608 | | | | | 23 |
| 954 | 786 | 150,403 | 151,189 | | | | | 24 |
| 397.5 | 9,460 | 8,416,071 | 8,425,531 | | | | | 25 |
| 397.5 | 188,018 | 1,140,352 | 1,328,370 | | | | | 26 |
| 397.5 | 33,968 | 3,135,741 | 3,169,709 | | | | | 27 |
| 795 | 345,835 | 5,628,566 | 5,974,401 | | | | | 28 |
| 1272 | 426,295 | 1,227,204 | 1,653,499 | | | | | 29 |
| 795 | 58,030 | 1,563,521 | 1,621,551 | | | | | 30 |
| 397.5 | 40,115 | 1,103,562 | 1,143,677 | | | | | 31 |
| 397.5 | 100,353 | 2,113,630 | 2,213,983 | | | | | 32 |
| 397.5 | 80,861 | 1,717,926 | 1,798,787 | | | | | 33 |
| 795 | 13,733 | 1,490,422 | 1,504,155 | | | | | 34 |
| 397.5 | 5,546 | 325,980 | 331,526 | | | | | 35 |
| | 87,473,552 | 1,741,496,237 | 1,828,969,789 | 93,337 | 16,204,998 | 803,249 | 17,101,584 | 36 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## TRANSMISSION LINE STATISTICS

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

| Line No. | DESIGNATION | | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) | | Type of Supporting Structure | LENGTH (Pole miles) (In the case of underground lines report circuit miles) | | Number Of Circuits |
|---|---|---|---|---|---|---|---|---|
| | From (a) | To (b) | Operating (c) | Designed (d) | (e) | On Structure of Line Designated (f) | On Structures of Another Line (g) | (h) |
| 1 | Sigurd Substation, UT | West Cedar Substation, U | 138.00 | 138.00 | Wood - H | 120.00 | | 1 |
| 2 | Ben Lomond Sub., UT | El Monte Substation, UT | 138.00 | 138.00 | Wood - H Sub | 19.00 | | 1 |
| 3 | Cottonwood Sub., UT | Ninetieth South Sub, UT | 138.00 | 138.00 | Wood - SP | 11.00 | | 1 |
| 4 | Terminal Substation, UT | Rowley Substation, UT | 138.00 | 138.00 | Wood - H | 56.00 | | 1 |
| 5 | Huntington Plant, UT | McFadden Substation, UT | 138.00 | 138.00 | Wood - H | 7.00 | | 1 |
| 6 | Ben Lomond Sub., UT | El Monte Substation, UT | 138.00 | 138.00 | Wood - H | 13.00 | | 1 |
| 7 | Cottonwood Sub., UT | Silvercreek Sub., UT | 138.00 | 138.00 | Wood - SP | 37.00 | | 1 |
| 8 | Ninetieth South Sub, UT | Taylorsville Sub., UT | 138.00 | 138.00 | Wood - SP | 9.00 | | 1 |
| 9 | Gadsby Plant, UT | McClelland Sub., UT | 138.00 | 138.00 | Wood - SP | 4.00 | | 1 |
| 10 | Ninetieth South Sub, UT | Oquirrh Substation, UT | 138.00 | 138.00 | Wood - SP | 10.00 | | 2 |
| 11 | Nebo, UT | Jerusalem, UT | 138.00 | 138.00 | Wood Tower | 26.00 | | 1 |
| 12 | Ben Lomond Sub., UT | Western Zircon Sub., UT | 138.00 | 138.00 | Wood - H | 14.00 | | 1 |
| 13 | Tooele Substation, UT | Oquirrh Substation, UT | 138.00 | 138.00 | Wood - SP | 21.00 | | 1 |
| 14 | Wheelon Substation, UT | Nucor Steel Sub., UT | 138.00 | 138.00 | Wood - H | 14.00 | 4.00 | 1 |
| 15 | Nebo Substation, UT | Martin-Marietta Sub., UT | 138.00 | 138.00 | Wood - H | 30.00 | | 1 |
| 16 | West Cedar Sub., UT | Middleton Substation., U | 138.00 | 138.00 | Wood - H | 69.00 | | 1 |
| 17 | Gadsby Plant, UT | Terminal Substation, UT | 138.00 | 138.00 | Wood - H | 6.00 | | 1 |
| 18 | Oquirrh Substation, UT | Kennecott Sub., UT | 138.00 | 138.00 | Wood - H | 4.00 | | 1 |
| 19 | Oquirrh Substation, UT | Barney Substation, UT | 138.00 | 138.00 | Wood - HS | 7.00 | | 2 |
| 20 | West Cedar Sub., UT | Pepcon Substation, UT | 138.00 | 138.00 | Wood - SP | 13.00 | | 1 |
| 21 | Taylorsville Substation, UT | Mid-Valley Substation, U | 138.00 | 138.00 | Steel - SP | 5.00 | | 1 |
| 22 | Warren Substation, UT | Kimberly Clark Sub., UT | 138.00 | 138.00 | Wood - HP | 1.00 | | 1 |
| 23 | Honeyville, UT | Promontory, UT | 138.00 | 138.00 | Wood Tower | 22.00 | | 1 |
| 24 | Ninetieth South Sub, UT | Hale Plant, UT | 138.00 | 138.00 | Wood Tower | 51.00 | | 1 |
| 25 | Dumas, UT | Bimple, UT | 138.00 | 138.00 | Wood Tower | 4.00 | | 1 |
| 26 | Columbia Sub, UT | Sunnyside Co. Gen., UT | 138.00 | 138.00 | Wood Tower | 2.00 | | 1 |
| 27 | Syracuse Sub, UT | Ben Lomond Sub, UT | 138.00 | 138.00 | Steel- D-P | 26.00 | | 1 |
| 28 | Hale Plant, UT | Midway Sub, UT | 138.00 | 138.00 | Wood - H | 19.00 | | 1 |
| 29 | Jordan 138 kV, UT | Fifth West 138 kV, UT | 138.00 | 138.00 | Steel Tower | 1.00 | | 1 |
| 30 | Gadsby 138 kV, UT | Jordan 138 kV, UT | 138.00 | 138.00 | Steel Tower | 1.00 | | 1 |
| 31 | Panther, UT | Willow Creek, UT | 138.00 | 138.00 | Steel Tower | 1.00 | | 1 |
| 32 | Hammer Substation, UT | Butlerville Substation, UT | 138.00 | 138.00 | Steel Tower | 5.00 | | 1 |
| 33 | Midway Substation, UT | Silver Creek Sub, UT | 138.00 | 138.00 | Steel Tower | 14.00 | | 1 |
| 34 | Midway Substation, UT | Cottonwood Sub, UT | 138.00 | 138.00 | Steel Tower | 10.00 | | 1 |
| 35 | McFadden Substation, UT | Blackhawk Substation, UT | 138.00 | 138.00 | Wood - H | 11.00 | | 1 |
| 36 | | | | | TOTAL | 16,292.00 | 150.00 | 220 |

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) Land (j) | Construction and Other Costs (k) | Total Cost (l) | EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | Line No. |
|---|---|---|---|---|---|---|---|---|
| 397.5 | 62,155 | 3,545,919 | 3,608,074 | | | | | 1 |
| 795 | 18,845 | 853,733 | 872,578 | | | | | 2 |
| 795 | 549,064 | 2,246,411 | 2,795,475 | | | | | 3 |
| 795 | 222,286 | 2,430,157 | 2,652,443 | | | | | 4 |
| 397.5 | 265 | 238,869 | 239,134 | | | | | 5 |
| 795 | 24,901 | 1,023,940 | 1,048,841 | | | | | 6 |
| 397.5 | 177,824 | 6,188,399 | 6,366,223 | | | | | 7 |
| 795 | 5,178 | 2,551,865 | 2,557,043 | | | | | 8 |
| 795 | 56,759 | 920,618 | 977,377 | | | | | 9 |
| 795 | 243,445 | 3,569,523 | 3,812,968 | | | | | 10 |
| 397.5 | 253,539 | 2,258,388 | 2,511,927 | | | | | 11 |
| 250 | 96,457 | 995,215 | 1,091,672 | | | | | 12 |
| 795 | 252,891 | 3,138,911 | 3,391,802 | | | | | 13 |
| 795 | 46,947 | 909,120 | 956,067 | | | | | 14 |
| 397.5 | 66,452 | 1,809,241 | 1,875,693 | | | | | 15 |
| 397.5 | 25,148 | 2,178,964 | 2,204,112 | | | | | 16 |
| 1272 | 668,771 | 810,472 | 1,479,243 | | | | | 17 |
| 795 | 4,055,798 | 256,188 | 4,311,986 | | | | | 18 |
| 795 | 16,668 | 457,439 | 474,107 | | | | | 19 |
| 795 | 43,590 | 1,272,268 | 1,315,858 | | | | | 20 |
| 1272 | 33,466 | 2,500,072 | 2,533,538 | | | | | 21 |
| 297.5 | 197,978 | 1,555,035 | 1,753,013 | | | | | 22 |
| 397.5 | 475,682 | 2,874,162 | 3,349,844 | | | | | 23 |
| 397.5 | 145,804 | 7,835,694 | 7,981,498 | | | | | 24 |
| 397.5 | | 2,940,561 | 2,940,561 | | | | | 25 |
| 397.5 | -41 | 2 | -39 | | | | | 26 |
| 1272 | | 353,104 | 353,104 | | | | | 27 |
| 397.5 | 246,503 | 4,038,881 | 4,285,384 | | | | | 28 |
| 1272 | 17 | 1,104,840 | 1,104,857 | | | | | 29 |
| 1272 | 755 | 381,900 | 382,655 | | | | | 30 |
| 397.5 | | 40,890 | 40,890 | | | | | 31 |
| | 188,391 | 3,364,794 | 3,553,185 | | | | | 32 |
| | | 2,770,396 | 2,770,396 | | | | | 33 |
| | 690,025 | 5,581,573 | 6,271,598 | | | | | 34 |
| | | 1,747,452 | 1,747,452 | | | | | 35 |
| | 87,473,552 | 1,741,496,237 | 1,828,969,789 | 93,337 | 16,204,998 | 803,249 | 17,101,584 | 36 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## TRANSMISSION LINE STATISTICS

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

| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | West Valley Sub., UT | Kearns Substation, UT | 138.00 | 138.00 | Wood - SP | 2.00 | | 1 |
| 2 | Syracuse Substation, UT | Clearfield South Sub., UT | 138.00 | 138.00 | Wood - SP | 1.00 | | 1 |
| 3 | Farmington Substation, UT | Parrish Substation, UT | 138.00 | 138.00 | Steel - DC | 5.00 | | 1 |
| 4 | Midvalley Substation, UT | Cottonwood Substation, UT | 138.00 | 138.00 | Wood - DC | 5.00 | | 1 |
| 5 | Taylorsville Substation, UT | West Valley Substation, UT | 138.00 | 138.00 | Steel - DC | 3.00 | 3.00 | 1 |
| 6 | Dynamo Sub, UT | Tri-City Sub, UT | 138.00 | 138.00 | Wood - SP | 2.00 | | 2 |
| 7 | Oqruirrh Sub, UT | Tri-City Sub, UT | 138.00 | 138.00 | Wood - SP | 22.00 | | 2 |
| 8 | Bridgerland Sub, UT | Green Canyon Sub, UT | 138.00 | 138.00 | Wood - SP | 16.00 | | 1 |
| 9 | Bonanza Substation, UT | Anadarko/Chapita, UT | 138.00 | 138.00 | Wood - SP | 7.00 | | 1 |
| 10 | 138 kV expenses | | | | | | | |
| 11 | | | | | | | | |
| 12 | Subtotal 138 kV | | | | | 2,140.00 | 12.00 | 92 |
| 13 | | | | | | | | |
| 14 | | | | | | | | |
| 15 | All 115 kV lines | | 115.00 | 115.00 | Wood & Steel | 1,583.00 | | |
| 16 | All 69 kV lines | | 69.00 | 69.00 | Wood & Steel | 2,968.00 | 1.00 | |
| 17 | All 57 kV lines | | 57.00 | 57.00 | Wood & Steel | 113.00 | | |
| 18 | All 46 kV lines | | 46.00 | 46.00 | Wood & Steel | 2,576.00 | | |
| 19 | | | | | | | | |
| 20 | | | | | | | | |
| 21 | Unclassified Plant at 12/31 | | | | | | | |
| 22 | Pleasant Grove Tap | Unclassified Plant | 138.00 | | | | | |
| 23 | Herriman-Oquirrh | Unclassified Plant | 138.00 | | | | | |
| 24 | Three Mile Knoll | Unclassified Plant | 138.00 | | | | | |
| 25 | Meridian-Malin | Unclassified Plant | 500.00 | | | | | |
| 26 | Walla Walla-Hells Canyon | Unclassified Plant | 230.00 | | | | | |
| 27 | Glenrock Wind Plant, WY | Windstar | 230.00 | 230.00 | Steel - SP | 13.00 | | 1 |
| 28 | Marengo 2 Wind Plant, WA | Marengo | 230.00 | 230.00 | Wood - H | 4.00 | | 1 |
| 29 | Unclassified Plant (Under | $1,000,000 Projects) | | | | | | |
| 30 | | | | | | | | |
| 31 | | | | | | | | |
| 32 | | | | | | | | |
| 33 | | | | | | | | |
| 34 | | | | | | | | |
| 35 | | | | | | | | |
| 36 | | | | | TOTAL | 16,292.00 | 150.00 | 220 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## TRANSMISSION LINE STATISTICS (Continued)

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

| Size of Conductor and Material (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) | |
| | | 268,234 | 268,234 | | | | | 1 |
| | | 677,376 | 677,376 | | | | | 2 |
| | | 897,031 | 897,031 | | | | | 3 |
| | | 4,655,525 | 4,655,525 | | | | | 4 |
| | | 2,002,980 | 2,002,980 | | | | | 5 |
| 2-795 | | 9,152,872 | 9,152,872 | | | | | 6 |
| 1557 | | 41,064,702 | 41,064,702 | | | | | 7 |
| 1272 | | 9,298,221 | 9,298,221 | | | | | 8 |
| 795 KCM ACSR | | 44,956 | 44,956 | | | | | 9 |
| | | | | | 1,981,479 | 13,807 | 1,995,286 | 10 |
| | | | | | | | | 11 |
| | 13,133,568 | 242,239,001 | 255,372,569 | | 1,981,479 | 13,807 | 1,995,286 | 12 |
| | | | | | | | | 13 |
| | | | | | | | | 14 |
| | 3,622,801 | 136,362,125 | 139,984,926 | 12 | 2,703,404 | 213,299 | 2,916,715 | 15 |
| | 3,386,199 | 212,710,644 | 216,096,843 | 5,068 | 2,805,142 | 117,095 | 2,927,305 | 16 |
| | 41,234 | 8,722,628 | 8,763,862 | 6 | 44,392 | 198 | 44,596 | 17 |
| | 6,122,436 | 192,919,349 | 199,041,785 | 83,324 | 2,342,538 | 52,199 | 2,478,061 | 18 |
| | | | | | | | | 19 |
| | | | | | | | | 20 |
| | | | | | | | | 21 |
| | | 2,261,775 | 2,261,775 | | | | | 22 |
| | | 2,987,270 | 2,987,270 | | | | | 23 |
| | | 3,976,854 | 3,976,854 | | | | | 24 |
| | | 1,510,366 | 1,510,366 | | | | | 25 |
| | | 1,542,409 | 1,542,409 | | | | | 26 |
| 1272 ACSR | | 5,233,054 | 5,233,054 | | | | | 27 |
| 795 ACSR | | 1,505,708 | 1,505,708 | | | | | 28 |
| | | 14,363,931 | 14,363,931 | | | | | 29 |
| | | | | | | | | 30 |
| | | | | | | | | 31 |
| | | | | | | | | 32 |
| | | | | | | | | 33 |
| | | | | | | | | 34 |
| | | | | | | | | 35 |
| | 87,473,552 | 1,741,496,237 | 1,828,969,789 | 93,337 | 16,204,998 | 803,249 | 17,101,584 | 36 |

**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 respondent's 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 respondent's 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.

**Schedule Page: 422.2 Line No.: 17 Column: f**

The Sheridan - Decker 230kV line was sold during 2008.

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(Next Page is 424)

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## TRANSMISSION LINES ADDED DURING YEAR

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

| Line No. | LINE DESIGNATION From (a) | LINE DESIGNATION To (b) | Line Length in Miles (c) | SUPPORTING STRUCTURE Type (d) | SUPPORTING STRUCTURE Average Number per Miles (e) | CIRCUITS PER STRUCTURE Present (f) | CIRCUITS PER STRUCTURE Ultimate (g) |
|---|---|---|---|---|---|---|---|
| 1 | Ninetieth South Sub., UT | Hale Plant, UT | 4.00 | Wood SP | 14.00 | 1 | 1 |
| 2 | Three Mile Knoll Sub., ID | Grace #1, ID | 2.00 | Wood SP | 14.00 | 1 | 1 |
| 3 | Three Mile Knoll Sub., ID | Grace #2, ID | 2.00 | Wood SP | 14.00 | 1 | 1 |
| 4 | Soda Plant, ID | Monsanto 1 Sub., ID | 2.00 | Wood SP | 14.00 | 1 | 1 |
| 5 | Soda Plant, ID | Monsanto 2 Sub., ID | 2.00 | Wood SP | 14.00 | 1 | 1 |
| 6 | Glenrock Wind Plant, WY | Windstar Substation, WY | 13.00 | Steel - SP | 11.00 | 1 | 1 |
| 7 | Marengo Wind Plant, WA | Marengo, WA | 4.00 | Wood - H | 8.00 | 1 | 1 |
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| 41 | | | | | | | |
| 42 | | | | | | | |
| 43 | | | | | | | |
| 44 | TOTAL | | 29.00 | | 89.00 | 7 | 7 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/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) | |
| 1272 | ACSR | Vertical 10' | 138 | | 1,264,904 | 1,480,174 | | 2,745,078 | 1 |
| 1272 | ACSR | Vertical 10' | 138 | | 310,074 | 310,073 | | 620,147 | 2 |
| 1272 | ACSR | Vertical 10' | 138 | | 321,109 | 321,108 | | 642,217 | 3 |
| 1272 | ACSR | Vertical 10' | 138 | | 278,620 | 278,620 | | 557,240 | 4 |
| 1272 | ACSR | Vertical 10' | 138 | | 276,774 | 276,774 | | 553,548 | 5 |
| 1272 | ACSR | Verical 10' | 230 | | 2,616,527 | 2,616,527 | | 5,233,054 | 6 |
| 795 | ACSR | Vertical 10' | 230 | | 752,854 | 752,854 | | 1,505,708 | 7 |
| | | | | | | | | | 8 |
| | | | | | | | | | 9 |
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| | | | | | | | | | 43 |
| | | | | | 5,820,862 | 6,036,130 | | 11,856,992 | 44 |

| Name of Respondent | This Report is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) X An Original<br>(2) _ A Resubmission | 03/31/2009 | 2008/Q4 |

FOOTNOTE DATA

***Schedule Page: 424 Line No.: 1 Column: c***

The Ninetieth South to Hale Plant line was converted from an existing 46kV line to a 138kV line.

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**(Next Page is 426)**

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

SUBSTATIONS

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

| Line No. | Name and Location of Substation | Character of Substation | VOLTAGE (In MVa) | | |
|---|---|---|---|---|---|
| | | | Primary | Secondary | Tertiary |
| | (a) | (b) | (c) | (d) | (e) |
| 1 | California | | | | |
| 2 | BELMONT SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 3 | BIG SPRINGS SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 4 | CANBY #2 | DISTRIBUTION-UNATTEN | 69.00 | 2.40 | |
| 5 | CASTELLA SUB | DISTRIBUTION-UNATTEN | 69.00 | 2.40 | |
| 6 | CLEAR LAKE SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 7 | CRESCENT CITY SUB | DISTRIBUTION-UNATTEN | 12.47 | 4.16 | |
| 8 | DOG CREEK SUB | DISTRIBUTION-UNATTEN | 69.00 | 2.40 | |
| 9 | DORRIS SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 10 | FORT JONES SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 11 | GASQUET SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 12 | GREENHORN SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 13 | HAMBURG SUB | DISTRIBUTION-UNATTEN | 69.00 | 2.40 | |
| 14 | HAPPY CAMP SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 15 | HORNBROOK SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 16 | INTERNATIONAL PAPER SUB | DISTRIBUTION-UNATTEN | 69.00 | 2.40 | |
| 17 | LAKE EARL SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 18 | LITTLE SHASTA SUB | DISTRIBUTION-UNATTEN | 69.00 | 7.20 | |
| 19 | LUCERNE SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 20 | MACDOEL SUB | DISTRIBUTION-UNATTEN | 69.00 | 20.80 | |
| 21 | MCCLOUD SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 22 | MILLER REDWOOD SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 23 | MONTAGUE SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 24 | MOUNT SHASTA SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 25 | NEWELL SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 26 | NORTH DUNSMUIR SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 27 | NORTHCREST SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 28 | NUTGLADE SUB | DISTRIBUTION-UNATTEN | 69.00 | 2.40 | |
| 29 | PATRICKS CREEK SUB | DISTRIBUTION-UNATTEN | 115.00 | 7.20 | |
| 30 | PEREZ SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 31 | REDWOOD SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 32 | SCOTT BAR SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 33 | SEIAD SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 34 | SHASTINA SUB | DISTRIBUTION-UNATTEN | 69.00 | 20.80 | |
| 35 | SHOTGUN CREEK SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 36 | SIMONSON SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 37 | SMITH RIVER SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 38 | SNOW BRUSH SUB | DISTRIBUTION-UNATTEN | 69.00 | 7.20 | |
| 39 | SOUTH DUNSMUIR SUB | DISTRIBUTION-UNATTEN | 69.00 | 4.16 | |
| 40 | TULELAKE SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| | | | | | | 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<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## SUBSTATIONS

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

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | TUNNEL SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 2 | TURKEY HILL SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 3 | WALKER BRYAN SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 4 | WEED SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 5 | YUBA SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 6 | YUROK SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 7 | Total | | 3186.47 | 484.96 | |
| 8 | Number of Substations- 45 | | | | |
| 9 | | | | | |
| 10 | ALTURAS | T/D-UNATTENDED | 115.00 | 12.47 | 69.00 |
| 11 | FALL CREEK HYDRO/SUB | T/D-UNATTENDED | 69.00 | 2.30 | |
| 12 | YREKA SUB | T/D-UNATTENDED | 115.00 | 12.47 | 69.00 |
| 13 | Total | | 299.00 | 27.24 | 138.00 |
| 14 | Number of Substations- 3 | | | | |
| 15 | | | | | |
| 16 | AGER SUB | TRANSMISSION-ATTEND | 115.00 | 69.00 | |
| 17 | COPCO #1 HYDRO PLANT | TRANSMISSION-ATTEND | 69.00 | 2.30 | |
| 18 | COPCO #2 230 SUB | TRANSMISSION-ATTEND | 230.00 | 115.00 | |
| 19 | COPCO #2 HYDRO PLANT | TRANSMISSION-ATTEND | 69.00 | 6.60 | |
| 20 | COPCO #2 SUB | TRANSMISSION-ATTEND | 69.00 | 12.47 | |
| 21 | CRAG VIEW SUB | TRANSMISSION-UNATTEN | 115.00 | 69.00 | |
| 22 | DEL NORTE SUB | TRANSMISSION-UNATTEN | 115.00 | 69.00 | |
| 23 | IRON GATE HYDRO PLANT | TRANSMISSION-UNATTEN | 69.00 | 6.60 | |
| 24 | WEED JUNCTION SUB | TRANSMISSION-UNATTEN | 115.00 | 69.00 | |
| 25 | Total | | 966.00 | 418.97 | |
| 26 | Number of Substations- 9 | | | | |
| 27 | | | | | |
| 28 | Idaho | | | | |
| 29 | ALEXANDER | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 30 | AMMON | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 31 | ANDERSON | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 32 | ARCO | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 33 | ARIMO | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 34 | BANCROFT SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 35 | BELSON SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 36 | BERENICE SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 37 | CAMAS SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 38 | CANYON CREEK SUB | DISTRIBUTION-UNATTEN | 69.00 | 24.90 | |
| 39 | CHESTERFIELD SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 40 | CINDER BUTTE SUB | DISTRIBUTION-UNATTEN | 161.00 | 12.47 | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 6 | 6 | | | | | 1 |
| 13 | 3 | | | | | 2 |
| 7 | 1 | | | | | 3 |
| 25 | 1 | | | | | 4 |
| 4 | 3 | | | | | 5 |
| 4 | 3 | | | | | 6 |
| 344 | 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 |
| 375 | 2 | | | | | 18 |
| 60 | 3 | 1 | | | | 19 |
| 2 | 3 | | | | | 20 |
| 19 | 3 | | | | | 21 |
| 150 | 2 | | | | | 22 |
| 19 | 1 | | | | | 23 |
| 38 | 3 | | | | | 24 |
| 696 | 26 | 3 | | | | 25 |
| | | | | | | 26 |
| | | | | | | 27 |
| | | | | | | 28 |
| 4 | 1 | | | | | 29 |
| 14 | 1 | | | | | 30 |
| 20 | 1 | | | | | 31 |
| 6 | 1 | | | | | 32 |
| 8 | 1 | | | | | 33 |
| 4 | 1 | | | | | 34 |
| 13 | 1 | | | | | 35 |
| 11 | 1 | | | | | 36 |
| 14 | 1 | | | | | 37 |
| 20 | 1 | | | | | 38 |
| 5 | 1 | | | | | 39 |
| 30 | 1 | 1 | | | | 40 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## SUBSTATIONS

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

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | CLEMENTS SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 2 | CLIFTON SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 3 | COVE SUB | DISTRIBUTION-UNATTEN | 46.00 | 6.60 | |
| 4 | DOWNEY SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 5 | DUBOIS SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 6 | EASTMONT SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 7 | EGIN SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 8 | EIGHT MILE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 9 | GEORGETOWN SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 10 | GRACE CITY SUBSTATION | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 11 | HAMER SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 12 | HAYES SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 13 | HENRY SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 14 | HOLBROOD SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 15 | HOOPES SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 16 | HORSLEY SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 17 | IDAHO FALLS SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 18 | INDIAN CREEK SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 19 | JEFFCO SUB | DISTRIBUTION-UNATTEN | 69.00 | 24.90 | |
| 20 | KETTLE SUB | DISTRIBUTION-UNATTEN | 69.00 | 24.90 | |
| 21 | LAVA SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 22 | LUND SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 23 | MCCAMMON SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 24 | MENAN SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 25 | MERRILL SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 26 | MILLER SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 27 | MONTPELIER SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 28 | MOODY SUB | DISTRIBUTION-UNATTEN | 69.00 | 24.90 | |
| 29 | NEWDALE SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 30 | OSGOOD SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 31 | PRESTON SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 32 | RAYMOND SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 33 | RENO SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 34 | REXBURG SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 35 | RIRIE SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 36 | ROBERTS SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 37 | RUDY SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 38 | SAND CREEK SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 39 | SANDUNE SUB | DISTRIBUTION-UNATTEN | 69.00 | 24.90 | |
| 40 | SHELLEY SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

SUBSTATIONS (Continued)

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

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

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 5 | 1 | | | | | 1 |
| 4 | 1 | | | | | 2 |
| 21 | 4 | | | | | 3 |
| 5 | 1 | | | | | 4 |
| 13 | 1 | | | | | 5 |
| 14 | 1 | | | | | 6 |
| 14 | 1 | | | | | 7 |
| 3 | 1 | | | | | 8 |
| 6 | 1 | | | | | 9 |
| 5 | 1 | | | | | 10 |
| 14 | 1 | | | | | 11 |
| 9 | 1 | | | | | 12 |
| 3 | 1 | | | | | 13 |
| 6 | 1 | | | | | 14 |
| 9 | 1 | | | | | 15 |
| 4 | 1 | | | | | 16 |
| 20 | 1 | | | | | 17 |
| 3 | 1 | | | | | 18 |
| 22 | 1 | | | | | 19 |
| 14 | 1 | | | | | 20 |
| 3 | 1 | | | | | 21 |
| 5 | 1 | | | | | 22 |
| 3 | 1 | | | | | 23 |
| 11 | 1 | | | | | 24 |
| 20 | 1 | | | | | 25 |
| 5 | 1 | | | | | 26 |
| 8 | 1 | | | | | 27 |
| 14 | 1 | | | | | 28 |
| 20 | 1 | | | | | 29 |
| 20 | 1 | | | | | 30 |
| 13 | 1 | | | | | 31 |
| 2 | 1 | | | | | 32 |
| 20 | 1 | | | | | 33 |
| 33 | 2 | | | | | 34 |
| 9 | 1 | | | | | 35 |
| 8 | 1 | | | | | 36 |
| 7 | 1 | | | | | 37 |
| 40 | 2 | | | | | 38 |
| 20 | 1 | | | | | 39 |
| 20 | 1 | | | | | 40 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## SUBSTATIONS

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

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | SMITH SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 2 | SODA SUB | DISTRIBUTION-UNATTEN | 138.00 | 7.20 | |
| 3 | SOUTH FORK SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 4 | SPUD SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 5 | ST. CHARLES SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 6 | SUGAR CITY SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 7 | SUNNYDELL SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 8 | TANNER SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 9 | TARGHEE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 10 | THORNTON SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 11 | UCON SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 12 | WATKINS SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 13 | WEBSTER SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 14 | WESTON SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 15 | WINDSPER SUB | DISTRIBUTION-UNATTEN | 69.00 | 24.90 | |
| 16 | Total | | 4301.00 | 898.93 | |
| 17 | Number of Substations- 67 | | | | |
| 18 | | | | | |
| 19 | MALAD SUB | T/D-UNATTENDED | 138.00 | 46.00 | 12.47 |
| 20 | MUD LAKE SUB | T/D-UNATTENDED | 69.00 | 12.47 | |
| 21 | RIGBY SUB | T/D-UNATTENDED | 161.00 | 12.47 | 69.00 |
| 22 | SAINT ANTHONY SUB | T/D-UNATTENDED | 69.00 | 46.00 | 12.47 |
| 23 | Total | | 437.00 | 116.94 | 93.94 |
| 24 | Number of Substations- 4 | | | | |
| 25 | | | | | |
| 26 | GRACE HYDRO | TRANSMISSION-ATTEND | 138.00 | 46.00 | 6.60 |
| 27 | AMPS SUB | TRANSMISSION-UNATTEN | 230.00 | 69.00 | |
| 28 | ANTELOPE SUB | TRANSMISSION-UNATTEN | 230.00 | 161.00 | |
| 29 | ASHTON PLANT | TRANSMISSION-UNATTEN | 46.00 | 2.40 | |
| 30 | BIG GRASSY SUB | TRANSMISSION-UNATTEN | 161.00 | 69.00 | |
| 31 | BONNEVILLE SUB | TRANSMISSION-UNATTEN | 161.00 | 69.00 | |
| 32 | CARIBOU SUB | TRANSMISSION-UNATTEN | 138.00 | 46.00 | |
| 33 | CONDA SUB | TRANSMISSION-UNATTEN | 138.00 | 46.00 | |
| 34 | FISH CREEK SUB | TRANSMISSION-UNATTEN | 161.00 | 46.00 | |
| 35 | FRANKLIN SUB | TRANSMISSION-UNATTEN | 138.00 | 46.00 | |
| 36 | GOSHEN SUB | TRANSMISSION-UNATTEN | 345.00 | 161.00 | 46.00 |
| 37 | JEFFERSON SUB | TRANSMISSION-UNATTEN | 161.00 | 69.00 | |
| 38 | LIFTON HYDRO | TRANSMISSION-UNATTEN | 69.00 | 2.30 | |
| 39 | ONEIDA SUB | TRANSMISSION-UNATTEN | 138.00 | 12.50 | |
| 40 | OVID SUB | TRANSMISSION-UNATTEN | 138.00 | 69.00 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 20 | 1 | | | | | 1 |
| 22 | 1 | | | | | 2 |
| 14 | 1 | | | | | 3 |
| 8 | 1 | | | | | 4 |
| 5 | 1 | | | | | 5 |
| 13 | 1 | | | | | 6 |
| 13 | 1 | | | | | 7 |
| 4 | 1 | | | | | 8 |
| 4 | 1 | | | | | 9 |
| 7 | 1 | | | | | 10 |
| 7 | 1 | | | | | 11 |
| 14 | 1 | | | | | 12 |
| 20 | 1 | | | | | 13 |
| 4 | 1 | | | | | 14 |
| 20 | 1 | | | | | 15 |
| 799 | 72 | 1 | | | | 16 |
| | | | | | | 17 |
| | | | | | | 18 |
| 71 | 4 | 1 | | | | 19 |
| 14 | 1 | | | | | 20 |
| 189 | 4 | | | | | 21 |
| 40 | 2 | | | | | 22 |
| 314 | 11 | 1 | | | | 23 |
| | | | | | | 24 |
| | | | | | | 25 |
| 115 | 4 | | | | | 26 |
| 75 | 2 | 1 | | | | 27 |
| 250 | 1 | | | | | 28 |
| 25 | 3 | | | | | 29 |
| 67 | 1 | | | | | 30 |
| 67 | 1 | | | | | 31 |
| 27 | 1 | | | | | 32 |
| 67 | 1 | | | | | 33 |
| 25 | 3 | | | | | 34 |
| 75 | 1 | | | | | 35 |
| 763 | 8 | 1 | | | | 36 |
| 233 | 3 | | | | | 37 |
| 6 | 2 | | | | | 38 |
| 40 | 2 | | | | | 39 |
| 30 | 1 | | | | | 40 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## SUBSTATIONS

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

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | SCOVILLE SUB | TRANSMISSION-UNATTEN | 138.00 | 69.00 | 46.00 |
| 2 | SUGARMILL SUB | TRANSMISSION-UNATTEN | 161.00 | 46.00 | 69.00 |
| 3 | THREEMILE KNOLL SUB | TRANSMISSION-UNATTEN | 345.00 | 138.00 | 46.00 |
| 4 | TREASURETON SUB | TRANSMISSION-UNATTEN | 230.00 | 138.00 | |
| 5 | Total | | 3266.00 | 1305.20 | 213.60 |
| 6 | Number of Substations- 19 | | | | |
| 7 | | | | | |
| 8 | Oregon | | | | |
| 9 | 26TH STREET | DISTRIBUTION-UNATTEN | 20.80 | 4.16 | |
| 10 | 35TH STREET | DISTRIBUTION-UNATTEN | 20.80 | 2.40 | |
| 11 | AGNESS AVE | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 12 | ALDERWOOD | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 13 | ARLINGTON | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 14 | ATHENA | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 15 | BANDON TIE SUB | DISTRIBUTION-UNATTEN | 20.80 | 12.47 | |
| 16 | BEACON SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 17 | BEALL LANE SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 18 | BEATTY SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 19 | BELKNAP | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 20 | BLALOCK SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 21 | BLOSS SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 22 | BLY SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 23 | BOISE CASCADE SUB | DISTRIBUTION-UNATTEN | 69.00 | 11.00 | |
| 24 | BONANZA SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 25 | BOND STREET SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.50 | |
| 26 | BROOKHURST SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 27 | BROWNSVILLE SUB | DISTRIBUTION-UNATTEN | 69.00 | 20.80 | |
| 28 | BRYANT SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 29 | BUCHANAN SUB | DISTRIBUTION-UNATTEN | 115.00 | 20.80 | |
| 30 | BUCKAROO SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 31 | CAMPBELL SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 32 | CANNON BEACH SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 33 | CARNES SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 34 | CASEBEER SUB | DISTRIBUTION-UNATTEN | 69.00 | 20.80 | |
| 35 | CAVEMAN SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 36 | CHERRY LANE SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 37 | CHILOQUIN MARKET SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 38 | CHINA HAT SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 39 | CIRCLE BLVD SUB | DISTRIBUTION-UNATTEN | 115.00 | 20.80 | |
| 40 | CLEVELAND AVE SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa)<br>(f) | Number of Transformers In Service<br>(g) | Number of Spare Transformers<br>(h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT<br>Type of Equipment<br>(i) | Number of Units<br>(j) | Total Capacity (In MVa)<br>(k) | Line No. |
|---|---|---|---|---|---|---|
| 76 | 2 | | | | | 1 |
| 168 | 3 | | | | | 2 |
| 700 | 1 | | | | | 3 |
| 533 | 2 | | | | | 4 |
| 3342 | 42 | 2 | | | | 5 |
| | | | | | | 6 |
| | | | | | | 7 |
| | | | | | | 8 |
| 5 | 1 | | | | | 9 |
| 30 | 6 | | | | | 10 |
| 25 | 1 | | | | | 11 |
| 25 | 1 | | | | | 12 |
| 5 | 1 | | | | | 13 |
| 9 | 1 | | | | | 14 |
| 8 | 3 | 1 | | | | 15 |
| 11 | 3 | | | | | 16 |
| 25 | 1 | | | | | 17 |
| 6 | 1 | | | | | 18 |
| 40 | 2 | | | | | 19 |
| 2 | 3 | | | | | 20 |
| 32 | 2 | | | | | 21 |
| 8 | 3 | | | | | 22 |
| 3 | 1 | | | | | 23 |
| 8 | 3 | | | | | 24 |
| 25 | 1 | | | | | 25 |
| 50 | 2 | | | | | 26 |
| 13 | 1 | | | | | 27 |
| 34 | 2 | | | | | 28 |
| 40 | 2 | | | | | 29 |
| 34 | 2 | | | | | 30 |
| 20 | 1 | | | | | 31 |
| 13 | 1 | | | | | 32 |
| 9 | 3 | | | | | 33 |
| 20 | 1 | | | | | 34 |
| 45 | 2 | | | | | 35 |
| 25 | 1 | | | | | 36 |
| 5 | 3 | | | | | 37 |
| 25 | 1 | | | | | 38 |
| 80 | 2 | | | | | 39 |
| 45 | 2 | | | | | 40 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

SUBSTATIONS

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

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | CLINE FALLS HYDRO | DISTRIBUTION-UNATTEN | 12.47 | 2.40 | |
| 2 | CLOAKE SUB | DISTRIBUTION-UNATTEN | 69.00 | 20.80 | |
| 3 | COBURG SUB | DISTRIBUTION-UNATTEN | 69.00 | 20.80 | |
| 4 | COLISEUM SUB | DISTRIBUTION-UNATTEN | 20.80 | 4.16 | |
| 5 | COLUMBIA SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | 57.00 |
| 6 | COOS RIVER SUB | DISTRIBUTION-UNATTEN | 115.00 | 20.80 | |
| 7 | COQUILLE SUB | DISTRIBUTION-UNATTEN | 115.00 | 20.80 | |
| 8 | CREEK SUB | DISTRIBUTION-UNATTEN | 69.00 | 34.50 | |
| 9 | CROOKED RIVER RANCH SUB | DISTRIBUTION-UNATTEN | 69.00 | 20.80 | |
| 10 | CROWFOOT SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 11 | CULLY SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 12 | CULVER SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 13 | CUTLER CITY SUB | DISTRIBUTION-UNATTEN | 20.80 | 4.16 | |
| 14 | DAIRY SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 15 | DALLAS SUB | DISTRIBUTION-UNATTEN | 115.00 | 20.80 | |
| 16 | DALREED SUB | DISTRIBUTION-UNATTEN | 230.00 | 34.50 | |
| 17 | DESCHUTES SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 18 | DEVILS LAKE SUB | DISTRIBUTION-UNATTEN | 115.00 | 20.80 | |
| 19 | DIXON SUB | DISTRIBUTION-UNATTEN | 115.00 | 4.16 | |
| 20 | DODGE BRIDGE SUB | DISTRIBUTION-UNATTEN | 69.00 | 20.80 | |
| 21 | EAST VALLEY SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 22 | EMPIRE SUB | DISTRIBUTION-UNATTEN | 115.00 | 20.80 | |
| 23 | ENTERPRISE SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 24 | FERN HILL SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 25 | FIELDER CREEK SUB | DISTRIBUTION-UNATTEN | 115.00 | 20.80 | |
| 26 | FOOTHILLS SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 27 | FRALEY SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 28 | GARDEN VALLEY SUB | DISTRIBUTION-UNATTEN | 69.00 | 20.80 | |
| 29 | GAZLEY SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 30 | GLENDALE SUB | DISTRIBUTION-UNATTEN | 230.00 | 12.47 | |
| 31 | GLENEDEN SUB | DISTRIBUTION-UNATTEN | 20.80 | 4.16 | |
| 32 | GLIDE SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 33 | GOLD HILL SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 34 | GORDON HOLLOW SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 35 | GOSHEN SUB | DISTRIBUTION-UNATTEN | 115.00 | 20.80 | |
| 36 | GRANT STREET SUB | DISTRIBUTION-UNATTEN | 115.00 | 20.80 | |
| 37 | GRASS VALLEY SUB | DISTRIBUTION-UNATTEN | 20.80 | 4.16 | |
| 38 | GREEN SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 39 | GRIFFIN CREEK SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 40 | HAMAKER SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 1 | 3 | | | | | 1 |
| 20 | 1 | | | | | 2 |
| 1 | 3 | | | | | 3 |
| 9 | 2 | | | | | 4 |
| 55 | 2 | 1 | | | | 5 |
| 20 | 1 | | | | | 6 |
| 40 | 2 | | | | | 7 |
| 5 | 1 | | | | | 8 |
| 25 | 2 | | | | | 9 |
| 20 | 1 | | | | | 10 |
| 25 | 1 | | | | | 11 |
| 13 | 1 | | | | | 12 |
| 2 | 3 | | | | | 13 |
| 25 | 1 | | | | | 14 |
| 50 | 2 | | | | | 15 |
| 75 | 3 | | | | | 16 |
| 13 | 1 | | | | | 17 |
| 50 | 2 | | | | | 18 |
| 7 | 1 | | | | | 19 |
| 13 | 1 | | | | | 20 |
| 45 | 2 | | | | | 21 |
| 20 | 1 | | | | | 22 |
| 19 | 2 | | | | | 23 |
| 13 | 1 | | | | | 24 |
| 25 | 1 | | | | | 25 |
| 21 | 4 | | | | | 26 |
| 5 | 3 | | | | | 27 |
| 20 | 1 | | | | | 28 |
| 8 | 3 | | | | | 29 |
| 25 | 2 | | | | | 30 |
| 5 | 1 | | | | | 31 |
| 13 | 1 | | | | | 32 |
| 11 | 3 | | | | | 33 |
| 6 | 1 | | | | | 34 |
| 20 | 1 | | | | | 35 |
| 45 | 2 | | | | | 36 |
| 1 | 4 | | | | | 37 |
| 25 | 1 | | | | | 38 |
| 20 | 1 | | | | | 39 |
| 8 | 3 | | | | | 40 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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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<br>(a) | Character of Substation<br>(b) | VOLTAGE (In MVa)<br>Primary<br>(c) | Secondary<br>(d) | Tertiary<br>(e) |
|---|---|---|---|---|---|
| 1 | HARRISBURG SUB | DISTRIBUTION-UNATTEN | 69.00 | 20.80 | |
| 2 | HENLEY SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 3 | HERMISTON SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 4 | HILLVIEW SUB | DISTRIBUTION-UNATTEN | 115.00 | 20.80 | |
| 5 | HINKLE SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 6 | HOLLADAY SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 7 | HOLLYWOOD SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 8 | HOOD RIVER SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 9 | HORNET SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 10 | INDEPENDENCE SUB | DISTRIBUTION-UNATTEN | 69.00 | 20.80 | |
| 11 | JACKSONVILLE SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | 69.00 |
| 12 | JEFFERSON SUB | DISTRIBUTION-UNATTEN | 69.00 | 20.80 | |
| 13 | JEROME PRAIRIE SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 14 | JORDAN POINT SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 15 | JOSEPH SUB | DISTRIBUTION-UNATTEN | 20.80 | 12.47 | |
| 16 | JUNCTION CITY SUB | DISTRIBUTION-UNATTEN | 69.00 | 20.80 | |
| 17 | KENWOOD SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 18 | KILLINGWORTH SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 19 | KNAPPA SVENSEN SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 20 | LAKEPORT SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 21 | LAKEVIEW SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 22 | LANCASTER SUB | DISTRIBUTION-UNATTEN | 69.00 | 20.80 | |
| 23 | LEBANON SUB | DISTRIBUTION-UNATTEN | 115.00 | 20.80 | |
| 24 | LINCOLN SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 25 | LOCKHART SUB | DISTRIBUTION-UNATTEN | 115.00 | 20.80 | |
| 26 | LYONS SUB | DISTRIBUTION-UNATTEN | 69.00 | 20.80 | |
| 27 | MADRAS SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 28 | MALLORY SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 29 | MARYS RIVER SUB | DISTRIBUTION-UNATTEN | 115.00 | 20.80 | |
| 30 | MEDCO SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 31 | MEDFORD | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 32 | MERLIN SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 33 | MERRILL SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 34 | MINAM SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 35 | MODOC SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 36 | MORO SUB | DISTRIBUTION-UNATTEN | 20.80 | 2.40 | |
| 37 | MURDER CREEK SUB | DISTRIBUTION-UNATTEN | 115.00 | 20.80 | |
| 38 | MYRTLE CREEK SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 39 | MYRTLE POINT SUB | DISTRIBUTION-UNATTEN | 115.00 | 20.80 | |
| 40 | NELSCOTT SUB | DISTRIBUTION-UNATTEN | 20.80 | 4.16 | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa)<br>(f) | Number of Transformers In Service<br>(g) | Number of Spare Transformers<br>(h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT<br>Type of Equipment<br>(i) | Number of Units<br>(j) | Total Capacity (In MVa)<br>(k) | Line No. |
|---|---|---|---|---|---|---|
| 13 | 1 | | | | | 1 |
| 6 | 3 | | | | | 2 |
| 40 | 2 | | | | | 3 |
| 45 | 2 | | | | | 4 |
| 20 | 1 | | | | | 5 |
| 75 | 3 | | | | | 6 |
| 50 | 2 | | | | | 7 |
| 40 | 2 | | | | | 8 |
| 20 | 1 | | | | | 9 |
| 20 | 1 | | | | | 10 |
| 75 | 2 | | | | | 11 |
| 13 | 1 | | | | | 12 |
| 20 | 1 | | | | | 13 |
| 20 | 1 | | | | | 14 |
| 6 | 1 | 1 | | | | 15 |
| 25 | 2 | | | | | 16 |
| 3 | 3 | | | | | 17 |
| 40 | 2 | | | | | 18 |
| 6 | 1 | | | | | 19 |
| 50 | 2 | | | | | 20 |
| 9 | 3 | | | | | 21 |
| 13 | 3 | | | | | 22 |
| 40 | 2 | | | | | 23 |
| 105 | 3 | | | | | 24 |
| 40 | 2 | | | | | 25 |
| 9 | 1 | | | | | 26 |
| 25 | 2 | | | | | 27 |
| 25 | 1 | | | | | 28 |
| 20 | 1 | | | | | 29 |
| 20 | 1 | | | | | 30 |
| 79 | 14 | | | | | 31 |
| 45 | 2 | | | | | 32 |
| 17 | 6 | | | | | 33 |
| | 1 | | | | | 34 |
| 6 | 3 | | | | | 35 |
| 2 | 3 | | | | | 36 |
| 100 | 4 | | | | | 37 |
| 14 | 1 | | | | | 38 |
| 9 | 1 | | | | | 39 |
| 4 | 1 | | | | | 40 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

SUBSTATIONS

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

| Line No. | Name and Location of Substation<br>(a) | Character of Substation<br>(b) | VOLTAGE (In MVa) Primary<br>(c) | Secondary<br>(d) | Tertiary<br>(e) |
|---|---|---|---|---|---|
| 1 | NEW O'BRIEN SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 2 | OAK KNOLL SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 3 | OAKLAND SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 4 | ORCHARD STREET SUB | DISTRIBUTION-UNATTEN | 12.47 | 4.16 | |
| 5 | OVERPASS SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 6 | PALLETTE SUB | DISTRIBUTION-UNATTEN | 69.00 | 20.80 | |
| 7 | PARK STREET SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 8 | PARKROSE SUB | DISTRIBUTION-UNATTEN | 57.00 | 12.47 | |
| 9 | PENDLETON SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 10 | PILOT ROCK SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 11 | POWELL BUTTE SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 12 | PRINEVILLE SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 13 | PROVOLT SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 14 | QUEEN AVE SUB | DISTRIBUTION-UNATTEN | 69.00 | 20.80 | |
| 15 | RED BLANKET SUB | DISTRIBUTION-UNATTEN | 69.00 | 4.16 | |
| 16 | REDMOND SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 17 | RICH MANUFACTURING SUB | DISTRIBUTION-UNATTEN | 57.00 | 12.47 | |
| 18 | RIDDLE SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 19 | RIDDLE VENEER SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 20 | ROGUE RIVER SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 21 | ROSEBURG SUB | DISTRIBUTION-UNATTEN | 115.00 | 20.80 | |
| 22 | ROSS AVE SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 23 | ROXY ANN SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.50 | |
| 24 | RUCH SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 25 | RUNNING Y SUB | DISTRIBUTION-UNATTEN | 69.00 | 20.80 | |
| 26 | RUSSELLVILLE SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 27 | SAGE ROAD SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 28 | SCENIC SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | 69.00 |
| 29 | SCIO SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 30 | SEASIDE SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 31 | SELMA SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 32 | SHASTA WAY SUB | DISTRIBUTION-UNATTEN | 12.47 | 4.16 | |
| 33 | SHEVLIN PARK | DISTRIBUTION-UNATTEN | 69.00 | 12.50 | |
| 34 | SIMTAG BOOSTER PUMP | DISTRIBUTION-UNATTEN | 34.50 | 4.16 | |
| 35 | SOUTH DUNES SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 36 | SOUTHGATE SUB | DISTRIBUTION-UNATTEN | 69.00 | 20.80 | |
| 37 | SPRAGUE RIVER SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 38 | STATE STREET SUB | DISTRIBUTION-UNATTEN | 115.00 | 20.80 | |
| 39 | STAYTON SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 40 | STEAMBOAT SUB | DISTRIBUTION-UNATTEN | 115.00 | 7.20 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 9 | 1 | | | | | 1 |
| 45 | 2 | | | | | 2 |
| 8 | 1 | | | | | 3 |
| 2 | 3 | | | | | 4 |
| 45 | 2 | | | | | 5 |
| 1 | 1 | 1 | | | | 6 |
| 40 | 2 | | | | | 7 |
| 39 | 2 | | | | | 8 |
| 46 | 7 | 1 | | | | 9 |
| 22 | 2 | | | | | 10 |
| 6 | 1 | | | | | 11 |
| 50 | 2 | | | | | 12 |
| 11 | 3 | | | | | 13 |
| 50 | 2 | | | | | 14 |
| 2 | 3 | | | | | 15 |
| 50 | 2 | | | | | 16 |
| 8 | 1 | | | | | 17 |
| 14 | 1 | | | | | 18 |
| 25 | 1 | | | | | 19 |
| 25 | 2 | | | | | 20 |
| 50 | 2 | | | | | 21 |
| 9 | 3 | | | | | 22 |
| 25 | 1 | | | | | 23 |
| 9 | 1 | | | | | 24 |
| 9 | 1 | | | | | 25 |
| 45 | 2 | | | | | 26 |
| 40 | 2 | | | | | 27 |
| 70 | 3 | | | | | 28 |
| 8 | 1 | | | | | 29 |
| 40 | 2 | | | | | 30 |
| 9 | 1 | | | | | 31 |
| 2 | 3 | | | | | 32 |
| 25 | 1 | | | | | 33 |
| 19 | 2 | | | | | 34 |
| 9 | 1 | | | | | 35 |
| 20 | 1 | | | | | 36 |
| 7 | 3 | | | | | 37 |
| 40 | 2 | | | | | 38 |
| 55 | 2 | | | | | 39 |
| | 1 | | | | | 40 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

SUBSTATIONS

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

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | STEVENS ROAD SUB | DISTRIBUTION-UNATTEN | 115.00 | 20.80 | |
| 2 | SUTHERLIN SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.00 | |
| 3 | SWEET HOME SUB | DISTRIBUTION-UNATTEN | 115.00 | 20.80 | |
| 4 | TAKELMA SUB | DISTRIBUTION-UNATTEN | 115.00 | 20.80 | |
| 5 | TALENT SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 6 | TEXUM SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 7 | TILLER SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 8 | TOLO SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 9 | UMAPINE SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 10 | UMATILLA SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 11 | US PLYWOOD SUB | DISTRIBUTION-UNATTEN | 20.80 | 4.16 | |
| 12 | VERNON SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 13 | VILAS SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 14 | VILLAGE GREEN SUB | DISTRIBUTION-UNATTEN | 115.00 | 20.80 | |
| 15 | VINE STREET SUB | DISTRIBUTION-UNATTEN | 69.00 | 20.80 | |
| 16 | WALLOWA SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 17 | WARM SPRINGS SUB | DISTRIBUTION-UNATTEN | 69.00 | 20.80 | |
| 18 | WARRENTON SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 19 | WASCO SUB | DISTRIBUTION-UNATTEN | 20.80 | 4.16 | |
| 20 | WECOMA BEACH SUB | DISTRIBUTION-UNATTEN | 20.80 | 4.16 | |
| 21 | WESTERN KRAFT SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 22 | WESTON SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 23 | WESTSIDE HYDRO/SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 24 | WEYERHAUSER SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 25 | WHITE CITY | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 26 | WILLOW COVE SUB | DISTRIBUTION-UNATTEN | 34.50 | 4.16 | |
| 27 | WINSTON SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 28 | YEW AVENUE SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.50 | |
| 29 | YOUNGS BAY SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 30 | Total | | 15141.81 | 2480.71 | 195.00 |
| 31 | Number of Substations- 181 | | | | |
| 32 | | | | | |
| 33 | ALBINA SUB | T/D-UNATTENDED | 115.00 | 12.47 | 69.00 |
| 34 | APPLEGATE SUB | T/D-UNATTENDED | 115.00 | 69.00 | 12.47 |
| 35 | ASHLAND MTN AVE SUB | T/D-UNATTENDED | 115.00 | 69.00 | 12.47 |
| 36 | BEND PLANT | T/D-UNATTENDED | 69.00 | 4.16 | 12.47 |
| 37 | CAVE JUNCTION SUB | T/D-UNATTENDED | 115.00 | 12.47 | 69.00 |
| 38 | HAZELWOOD SUB | T/D-UNATTENDED | 115.00 | 69.00 | 12.47 |
| 39 | KNOTT SUB | T/D-UNATTENDED | 115.00 | 12.47 | 57.00 |
| 40 | MILE HI SUB | T/D-UNATTENDED | 115.00 | 69.00 | 12.47 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 25 | 1 | | | | | 1 |
| 25 | 1 | | | | | 2 |
| 42 | 2 | | | | | 3 |
| 13 | 1 | | | | | 4 |
| 50 | 2 | | | | | 5 |
| 17 | 6 | | | | | 6 |
| 1 | 1 | | | | | 7 |
| 11 | 1 | | | | | 8 |
| 13 | 1 | | | | | 9 |
| 25 | 2 | | | | | 10 |
| 13 | 2 | | | | | 11 |
| 50 | 2 | | | | | 12 |
| 25 | 1 | | | | | 13 |
| 40 | 2 | | | | | 14 |
| 22 | 4 | | | | | 15 |
| 7 | 1 | | | | | 16 |
| 13 | 3 | | | | | 17 |
| 25 | 2 | | | | | 18 |
| 3 | 3 | | | | | 19 |
| 3 | 1 | | | | | 20 |
| 50 | 2 | | | | | 21 |
| 22 | 2 | | | | | 22 |
| 23 | 9 | | | | | 23 |
| 40 | 2 | | | | | 24 |
| 60 | 3 | | | | | 25 |
| 28 | 3 | | | | | 26 |
| 23 | 3 | | | | | 27 |
| 25 | 1 | | | | | 28 |
| 37 | 2 | | | | | 29 |
| 4438 | 363 | 5 | | | | 30 |
| | | | | | | 31 |
| | | | | | | 32 |
| 177 | 9 | | | | | 33 |
| 65 | 2 | | | | | 34 |
| 70 | 2 | | | | | 35 |
| 23 | 3 | | | | | 36 |
| 70 | 2 | | | | | 37 |
| 132 | 4 | | | | | 38 |
| 187 | 8 | | | | | 39 |
| 39 | 4 | | | | | 40 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
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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 | PILOT BUTTE SUB | T/D-UNATTENDED | 230.00 | 69.00 | 12.47 |
| 2 | WINCHESTER SUB | T/D-UNATTENDED | 115.00 | 12.47 | 69.00 |
| 3 | Total | | 1219.00 | 399.04 | 338.82 |
| 4 | Number of Substations- 10 | | | | |
| 5 | | | | | |
| 6 | CLEARWATER #1 HYDRO PLANT | TRANSMISSION-ATTEND | 138.00 | 6.90 | |
| 7 | CLEARWATER #2 HYDRO PLANT | TRANSMISSION-ATTEND | 138.00 | 12.00 | |
| 8 | FISH CREEK HYDRO | TRANSMISSION-ATTEND | 115.00 | 6.90 | |
| 9 | JC BOYLE HYDRO | TRANSMISSION-ATTEND | 230.00 | 11.00 | |
| 10 | LEMOLO #1 HYDRO | TRANSMISSION-ATTEND | 115.00 | 12.47 | |
| 11 | LEMOLO #2 HYDRO | TRANSMISSION-ATTEND | 115.00 | 12.00 | |
| 12 | PROSPECT 1 HYDRO | TRANSMISSION-ATTEND | 69.00 | 2.30 | |
| 13 | PROSPECT 2 HYDRO | TRANSMISSION-ATTEND | 69.00 | 6.60 | |
| 14 | PROSPECT 3 HYDRO | TRANSMISSION-ATTEND | 69.00 | 12.47 | |
| 15 | TOKETEE HYDRO | TRANSMISSION-ATTEND | 115.00 | 6.90 | |
| 16 | BEND PLANT | TRANSMISSION-UNATTEN | 4.16 | 2.40 | |
| 17 | CALAPOOYA SUB | TRANSMISSION-UNATTEN | 230.00 | 69.00 | |
| 18 | CHILOQUIN SUB | TRANSMISSION-UNATTEN | 230.00 | 115.00 | 69.00 |
| 19 | COLD SPRINGS SUB | TRANSMISSION-UNATTEN | 230.00 | 69.00 | |
| 20 | COVE SUB | TRANSMISSION-UNATTEN | 230.00 | 69.00 | |
| 21 | DAYS CREEK SUB | TRANSMISSION-UNATTEN | 115.00 | 69.00 | |
| 22 | DIAMOND HILL SUB | TRANSMISSION-UNATTEN | 230.00 | 69.00 | |
| 23 | DIXONVILLE 115/230 SUB | TRANSMISSION-UNATTEN | 230.00 | 115.00 | 69.00 |
| 24 | DIXONVILLE 500 SUB | TRANSMISSION-UNATTEN | 500.00 | 230.00 | |
| 25 | EAGLE POINT HYDRO | TRANSMISSION-UNATTEN | 115.00 | 2.40 | |
| 26 | EAST SIDE HYDRO | TRANSMISSION-UNATTEN | 46.00 | 12.47 | |
| 27 | FISH HOLE SUB | TRANSMISSION-UNATTEN | 115.00 | 69.00 | |
| 28 | FRY SUB | TRANSMISSION-UNATTEN | 230.00 | 115.00 | |
| 29 | GRANTS PASS SUB | TRANSMISSION-UNATTEN | 230.00 | 115.00 | 69.00 |
| 30 | GREEN SPRINGS PLANT/SUB | TRANSMISSION-UNATTEN | 115.00 | 69.00 | |
| 31 | HURRICANE SUB | TRANSMISSION-UNATTEN | 230.00 | 69.00 | 2.40 |
| 32 | ISTHMUS SUB | TRANSMISSION-UNATTEN | 230.00 | 115.00 | |
| 33 | KENNEDY SUB | TRANSMISSION-UNATTEN | 69.00 | 57.00 | |
| 34 | KLAMATH FALLS SUB | TRANSMISSION-UNATTEN | 230.00 | 69.00 | |
| 35 | LONE PINE SUB | TRANSMISSION-UNATTEN | 230.00 | 115.00 | 69.00 |
| 36 | MERIDIAN SUB | TRANSMISSION-UNATTEN | 500.00 | 230.00 | |
| 37 | MONPAC SUB | TRANSMISSION-UNATTEN | 115.00 | 69.00 | |
| 38 | PONDEROSA SUB | TRANSMISSION-UNATTEN | 230.00 | 115.00 | |
| 39 | POWERDALE PLANT | TRANSMISSION-UNATTEN | 69.00 | 7.20 | |
| 40 | PROSPECT CENTRAL SUB | TRANSMISSION-UNATTEN | 115.00 | 69.00 | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 400 | 4 | | | | | 1 |
| 75 | 5 | | | | | 2 |
| 1238 | 43 | | | | | 3 |
| | | | | | | 4 |
| | | | | | | 5 |
| 17 | 3 | | | | | 6 |
| 31 | 3 | | | | | 7 |
| 13 | 3 | | | | | 8 |
| 89 | 2 | 1 | | | | 9 |
| 48 | 7 | 1 | | | | 10 |
| 40 | 4 | | | | | 11 |
| 5 | 3 | | | | | 12 |
| 40 | 6 | 1 | | | | 13 |
| 10 | 6 | | | | | 14 |
| 50 | 9 | | | | | 15 |
| 3 | 3 | | | | | 16 |
| 75 | 1 | | | | | 17 |
| 119 | 4 | | | | | 18 |
| 60 | 1 | | | | | 19 |
| 67 | 3 | | | | | 20 |
| 50 | 1 | | | | | 21 |
| 75 | 1 | | | | | 22 |
| 344 | 6 | | | | | 23 |
| 650 | 3 | 1 | | | | 24 |
| 3 | 1 | | | | | 25 |
| 3 | 3 | | | | | 26 |
| 7 | 3 | | | | | 27 |
| 500 | 2 | | | | | 28 |
| 458 | 4 | | | | | 29 |
| 19 | 3 | | | | | 30 |
| 29 | 2 | | | | | 31 |
| 250 | 1 | | | | | 32 |
| 33 | 1 | | | | | 33 |
| 251 | 6 | 1 | | | | 34 |
| 733 | 10 | | | | | 35 |
| 1300 | 6 | 1 | | | | 36 |
| 50 | 1 | | | | | 37 |
| 250 | 1 | | | | | 38 |
| 8 | 3 | 1 | | | | 39 |
| 47 | 4 | | | | | 40 |

## SUBSTATIONS

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

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | ROBERTS CREEK SUB | TRANSMISSION-UNATTEN | 115.00 | 69.00 | |
| 2 | SLIDE CREEK HYDRO | TRANSMISSION-UNATTEN | 115.00 | 7.00 | |
| 3 | SODA SPRINGS HYDRO | TRANSMISSION-UNATTEN | 115.00 | 7.00 | |
| 4 | TROUTDALE SUB | TRANSMISSION-UNATTEN | 230.00 | 115.00 | 69.00 |
| 5 | TUCKER SUB | TRANSMISSION-UNATTEN | 115.00 | 69.00 | |
| 6 | WALLOWA FALLS HYDRO | TRANSMISSION-UNATTEN | 20.80 | | |
| 7 | Total | | 6751.96 | 2462.01 | 347.40 |
| 8 | Number of Substations- 41 | | | | |
| 9 | | | | | |
| 10 | Utah | | | | |
| 11 | 106TH SOUTH SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.50 | |
| 12 | 118TH SOUTH SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 13 | 70TH SOUTH SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 14 | ALTAVIEW | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 15 | AMALGA | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 16 | AMERICAN FORK | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 17 | ARAGONITE | DISTRIBUTION-UNATTEN | 46.00 | 7.20 | |
| 18 | AURORA SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 19 | BANGERTER SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 20 | BEAR RIVER SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 21 | BENJAMIN SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 22 | BINGHAM SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 23 | BLUE CREEK | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 24 | BLUFF SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 25 | BLUFFDALE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 26 | BOTHWELL SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 27 | BOX ELDER SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 28 | BRIAN HEAD SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 29 | BRICKYARD SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 30 | BRIGHTON SUB | DISTRIBUTION-UNATTEN | 46.00 | 24.90 | |
| 31 | BROOKLAWN SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 32 | BRUNSWICK SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 33 | BURTON SUB | DISTRIBUTION-UNATTEN | 34.50 | 12.47 | |
| 34 | BUSH SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 35 | CANNON SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 36 | CANYONLANDS SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 37 | CAPITOL SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 38 | CARBIDE SUB | DISTRIBUTION-UNATTEN | 46.00 | 7.20 | |
| 39 | CARBONVILLE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 40 | CARLISLE SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.50 | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 50 | 1 | | | | | 1 |
| 21 | 3 | | | | | 2 |
| 13 | 3 | | | | | 3 |
| 500 | 3 | | | | | 4 |
| 100 | 2 | | | | | 5 |
| 2 | 3 | | | | | 6 |
| 6413 | 135 | 7 | | | | 7 |
| | | | | | | 8 |
| | | | | | | 9 |
| | | | | | | 10 |
| 30 | 1 | | | | | 11 |
| 30 | 1 | | | | | 12 |
| 30 | 1 | | | | | 13 |
| 45 | 2 | | | | | 14 |
| 11 | 1 | | | | | 15 |
| 30 | 1 | | | | | 16 |
| 1 | 1 | | | | | 17 |
| 3 | 1 | | | | | 18 |
| 50 | 1 | | | | | 19 |
| 17 | 2 | | | | | 20 |
| 2 | 1 | | | | | 21 |
| 11 | 1 | | | | | 22 |
| 2 | 3 | | | | | 23 |
| 1 | 3 | | | | | 24 |
| 9 | 1 | | | | | 25 |
| 4 | 1 | | | | | 26 |
| 14 | 1 | | | | | 27 |
| 14 | 1 | | | | | 28 |
| 9 | 1 | | | | | 29 |
| 26 | 2 | | | | | 30 |
| 6 | 1 | | | | | 31 |
| 60 | 3 | | | | | 32 |
| 11 | 3 | | | | | 33 |
| 9 | 1 | | | | | 34 |
| 13 | 1 | | | | | 35 |
| 1 | 1 | | | | | 36 |
| 20 | 1 | | | | | 37 |
| 3 | 1 | | | | | 38 |
| 6 | 1 | | | | | 39 |
| 30 | 1 | | | | | 40 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## SUBSTATIONS

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

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | CASTO SUBSTATION | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 2 | CENTENNIAL SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 3 | CENTERVILLE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 4 | CENTRAL SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 5 | CHAPEL HILL SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 6 | CHERRYWOOD SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 7 | CIRCLEVILLE SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 8 | CLEAR CREEK SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 9 | CLEAR LAKE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 10 | CLEARFIELD SOUTH | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 11 | CLINTON SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 12 | CLIVE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 13 | COALVILLE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 14 | COLD WATER CANYON SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 15 | COLEMAN SUB | DISTRIBUTION-UNATTEN | 138.00 | 69.00 | 12.47 |
| 16 | COLTON WELL SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 17 | COMMERCE SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.50 | |
| 18 | CORINNE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 19 | COVE FORT SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 20 | COZYDALE SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.50 | |
| 21 | CRESCENT JUNCTION SUB | DISTRIBUTION-UNATTEN | 46.00 | 7.20 | |
| 22 | CROSS HOLLOW SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 23 | CUDAHY SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 24 | DAMMERON VALLEY SUB | DISTRIBUTION-UNATTEN | 34.50 | 12.47 | |
| 25 | DECKER LAKE SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 26 | DELLE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 27 | DELTA SUB | DISTRIBUTION-UNATTEN | 46.00 | 69.00 | |
| 28 | DESERET SUB | DISTRIBUTION-UNATTEN | 46.00 | 4.16 | |
| 29 | DEWEYVILLE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 30 | DIMPLE DELL SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 31 | DIXIE DEER SUB | DISTRIBUTION-UNATTEN | 34.50 | 12.47 | |
| 32 | DRAPER SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 33 | DUMAS SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 34 | EAST BENCH SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 35 | EAST HYRUM SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 36 | EAST LAYTON SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 37 | EAST MILLCREEK SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 38 | EDEN SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 39 | ELBERTA SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 40 | ELK MEADOWS SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 25 | 1 | | | | | 1 |
| 40 | 2 | | | | | 2 |
| 22 | 1 | | | | | 3 |
| 2 | 1 | | | | | 4 |
| 30 | 1 | | | | | 5 |
| 25 | 1 | | | | | 6 |
| 3 | 1 | | | | | 7 |
| 4 | 1 | | | | | 8 |
| | 3 | | | | | 9 |
| 60 | 2 | | | | | 10 |
| 50 | 2 | | | | | 11 |
| 4 | 1 | | | | | 12 |
| 20 | 2 | | | | | 13 |
| 30 | 1 | | | | | 14 |
| 106 | 4 | | | | | 15 |
| 1 | 3 | | | | | 16 |
| 30 | 1 | | | | | 17 |
| 3 | 1 | | | | | 18 |
| 2 | 3 | | | | | 19 |
| 30 | 1 | | | | | 20 |
| 1 | 1 | | | | | 21 |
| 22 | 1 | | | | | 22 |
| 30 | 1 | | | | | 23 |
| 42 | 1 | | | | | 24 |
| 55 | 2 | | | | | 25 |
| 6 | 1 | | | | | 26 |
| 48 | 3 | | | | | 27 |
| 2 | 1 | | | | | 28 |
| 4 | 1 | | | | | 29 |
| 60 | 2 | | | | | 30 |
| 2 | 1 | | | | | 31 |
| 23 | 2 | | | | | 32 |
| 60 | 2 | | | | | 33 |
| 30 | 1 | | | | | 34 |
| 6 | 1 | | | | | 35 |
| 30 | 1 | | | | | 36 |
| 20 | 1 | | | | | 37 |
| 12 | 2 | | | | | 38 |
| 5 | 1 | | | | | 39 |
| 3 | 1 | | | | | 40 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original (2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## SUBSTATIONS

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

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | ELSINORE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 2 | EMERY CITY SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 3 | EMIGRATION SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 4 | ENOCH SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 5 | ENTERPRISE VALLEY SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 6 | EUREKA SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 7 | FARMINGTON SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 8 | FAYETTE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 9 | FERRON SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 10 | FIELDING SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.00 | |
| 11 | FIFTH WEST SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 12 | FLUX SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 13 | FOOL CREEK SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 14 | FOUNTAIN GREEN SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 15 | FREEDOM SUBSTATION | DISTRIBUTION-UNATTEN | 46.00 | 7.20 | |
| 16 | FRUIT HEIGHTS SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 17 | GARDEN CITY SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 18 | GATEWAY SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 19 | GORDON AVENUE SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.50 | |
| 20 | GOSHEN SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 21 | GRANGER SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 22 | GRANTSVILLE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 23 | GREEN RIVER SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 24 | GROW SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | 46.00 |
| 25 | GUNLOCK HYDRO | DISTRIBUTION-UNATTEN | 34.50 | 2.30 | |
| 26 | GUNNISON SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 27 | HAMILTON SUB | DISTRIBUTION-UNATTEN | 34.50 | 12.47 | |
| 28 | HAMMER SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 29 | HAVASU SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 30 | HELPER CITY SUB | DISTRIBUTION-UNATTEN | 46.00 | 4.16 | |
| 31 | HENEFER SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 32 | HERRIMAN SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 33 | HIAWATHA SUB | DISTRIBUTION-UNATTEN | 46.00 | 4.16 | |
| 34 | HIGHLAND DIST SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 35 | HOGGARD SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 36 | HOGLE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 37 | HOLDEN SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 38 | HOLLADAY SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 39 | HUNTER SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 40 | HUNTINGTON CITY SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |

## SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 2 | 1 | | | | | 1 |
| 3 | 3 | | | | | 2 |
| 25 | 1 | | | | | 3 |
| 14 | 1 | | | | | 4 |
| 10 | 1 | | | | | 5 |
| 3 | 1 | | | | | 6 |
| 30 | 1 | | | | | 7 |
| 1 | 2 | | | | | 8 |
| 5 | 1 | | | | | 9 |
| 6 | 1 | | | | | 10 |
| 30 | 1 | | | | | 11 |
| 4 | 1 | | | | | 12 |
| 2 | 1 | | | | | 13 |
| 2 | 1 | | | | | 14 |
| | 1 | | | | | 15 |
| 22 | 1 | | | | | 16 |
| 13 | 1 | | | | | 17 |
| 28 | 2 | 1 | | | | 18 |
| 30 | 1 | | | | | 19 |
| 2 | 1 | | | | | 20 |
| 43 | 2 | | | | | 21 |
| 24 | 1 | | | | | 22 |
| 5 | 2 | | | | | 23 |
| 72 | 3 | | | | | 24 |
| 1 | 1 | | | | | 25 |
| 11 | 1 | | | | | 26 |
| 1 | 3 | | | | | 27 |
| 60 | 2 | | | | | 28 |
| 3 | 1 | | | | | 29 |
| 3 | 3 | | | | | 30 |
| 4 | 1 | | | | | 31 |
| 30 | 1 | | | | | 32 |
| 1 | 3 | | | | | 33 |
| 25 | 1 | | | | | 34 |
| 50 | 2 | | | | | 35 |
| 22 | 1 | | | | | 36 |
| 4 | 1 | | | | | 37 |
| 32 | 2 | | | | | 38 |
| 22 | 1 | | | | | 39 |
| 13 | 2 | | | | | 40 |

## SUBSTATIONS

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

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | HURRICANE FIELDS SUB | DISTRIBUTION-UNATTEN | 34.50 | 12.47 | |
| 2 | IRON MOUNTAIN SUB | DISTRIBUTION-UNATTEN | 34.50 | 7.20 | |
| 3 | IRON SPRINGS SUB | DISTRIBUTION-UNATTEN | 34.50 | 12.47 | |
| 4 | IRONTON SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 5 | IVINS SUB | DISTRIBUTION-UNATTEN | 34.50 | 12.47 | |
| 6 | JORDAN NARROWS SUB | DISTRIBUTION-UNATTEN | 46.00 | 2.40 | |
| 7 | JORDAN PARK SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 8 | JORDANELLE SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 9 | JUAB SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 10 | JUNCTION SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 11 | KAIBAB SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 12 | KAMAS SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 13 | KANARRAVILLE SUB | DISTRIBUTION-UNATTEN | 34.50 | 12.47 | |
| 14 | KEARNS SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 15 | KENSINGTON SUB | DISTRIBUTION-UNATTEN | 46.00 | 4.16 | |
| 16 | LAKE PARK SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 17 | LARK SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 18 | LAYTON SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 19 | LEGRANDE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 20 | LEWISTON SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 21 | LINCOLN SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 22 | LINDON SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 23 | LISBON SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 24 | LITTLE MOUNTAIN SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 25 | LOAFER SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 26 | LOGAN CANYON SUB | DISTRIBUTION-UNATTEN | 46.00 | 7.20 | |
| 27 | LONE TREE SUB | DISTRIBUTION-UNATTEN | 34.50 | 12.47 | |
| 28 | LOWER BEAVER SUB | DISTRIBUTION-UNATTEN | 46.00 | 6.60 | |
| 29 | LYNNDYL SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 30 | MAESER SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 31 | MAGNA SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 32 | MANILA SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 33 | MANTUA SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 34 | MAPLETON SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 35 | MARRIOTT SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 36 | MARYSVALE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 37 | MATHIS SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 38 | MCCORNICK SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 39 | MCKAY SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 40 | MEADOWBROOK SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | 46.00 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 1 | 3 | | | | | 1 |
| 1 | 1 | | | | | 2 |
| 5 | 3 | | | | | 3 |
| 2 | 1 | | | | | 4 |
| 22 | 1 | | | | | 5 |
| 13 | 2 | | | | | 6 |
| 30 | 1 | | | | | 7 |
| 30 | 1 | | | | | 8 |
| 2 | 3 | | | | | 9 |
| 3 | 1 | | | | | 10 |
| 5 | 1 | | | | | 11 |
| 7 | 1 | | | | | 12 |
| 1 | 3 | | | | | 13 |
| 60 | 2 | | | | | 14 |
| 7 | 1 | | | | | 15 |
| 53 | 2 | | | | | 16 |
| 6 | 1 | | | | | 17 |
| 40 | 2 | | | | | 18 |
| 2 | 1 | | | | | 19 |
| 14 | 1 | | | | | 20 |
| 20 | 1 | | | | | 21 |
| 20 | 1 | | | | | 22 |
| 4 | 1 | | | | | 23 |
| 20 | 1 | | | | | 24 |
| | 1 | | | | | 25 |
| | 1 | | | | | 26 |
| 20 | 1 | | | | | 27 |
| 1 | 3 | | | | | 28 |
| 4 | 1 | | | | | 29 |
| 13 | 1 | | | | | 30 |
| 30 | 1 | | | | | 31 |
| 22 | 1 | | | | | 32 |
| 2 | 1 | | | | | 33 |
| 14 | 1 | | | | | 34 |
| 20 | 1 | | | | | 35 |
| 2 | 3 | | | | | 36 |
| 9 | 1 | | | | | 37 |
| 6 | 1 | | | | | 38 |
| 20 | 1 | | | | | 39 |
| 42 | 2 | | | | | 40 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

SUBSTATIONS

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

| Line No. | Name and Location of Substation<br>(a) | Character of Substation<br>(b) | VOLTAGE (In MVa) Primary<br>(c) | Secondary<br>(d) | Tertiary<br>(e) |
|---|---|---|---|---|---|
| 1 | MEDICAL SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 2 | MELLING SUB | DISTRIBUTION-UNATTEN | 34.50 | 4.16 | |
| 3 | MIDLAND SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 4 | MIDVALE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 5 | MILFORD SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 6 | MILFORD TV SUB | DISTRIBUTION-UNATTEN | 46.00 | 7.20 | |
| 7 | MILLVILLE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 8 | MINERSVILLE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 9 | MOAB CITY SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 10 | MONTEZUMA SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 11 | MOORE SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 12 | MORGAN SUB | DISTRIBUTION-UNATTEN | 46.00 | 4.16 | |
| 13 | MORONI SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 14 | MORTON COURT SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 15 | MOSS JUNCTION SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 16 | MOUNTAIN DELL SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 17 | MOUNTAIN GREEN SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 18 | MYTON SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 19 | NEW HARMONY SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 20 | NEWGATE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 21 | NEWTON SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 22 | NIBLEY SUB | DISTRIBUTION-UNATTEN | 46.00 | 24.90 | |
| 23 | NORTH BENCH SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 24 | NORTH CEDAR SUB | DISTRIBUTION-UNATTEN | 34.50 | 4.16 | |
| 25 | NORTH FIELDS SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 26 | NORTH LOGAN SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 27 | NORTH OGDEN SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 28 | NORTH SALT LAKE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 29 | NORTHEAST SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 30 | NORTHRIDGE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 31 | OAKLAND AVE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 32 | OAKLEY SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 33 | OGDEN DEFENSE DEPOT SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 34 | OLYMPUS SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 35 | OPHIR SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 36 | ORANGE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 37 | ORANGEVILLE SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 38 | OREM SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 39 | OREMET SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 40 | PACK CREEK RESERVOIR | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 58 | 4 | | | | | 1 |
| 5 | 1 | | | | | 2 |
| 30 | 1 | | | | | 3 |
| 25 | 1 | | | | | 4 |
| 14 | 1 | | | | | 5 |
| 1 | 1 | | | | | 6 |
| 13 | 1 | | | | | 7 |
| 2 | 1 | | | | | 8 |
| 19 | 2 | | | | | 9 |
| 13 | 1 | | | | | 10 |
| 3 | 1 | | | | | 11 |
| 3 | 1 | | | | | 12 |
| 6 | 1 | | | | | 13 |
| 25 | 1 | | | | | 14 |
| 6 | 3 | | | | | 15 |
| 5 | 1 | | | | | 16 |
| 6 | 1 | | | | | 17 |
| 6 | 1 | | | | | 18 |
| 7 | 1 | | | | | 19 |
| 20 | 1 | | | | | 20 |
| 5 | 1 | | | | | 21 |
| 14 | 1 | | | | | 22 |
| 25 | 1 | | | | | 23 |
| 5 | 1 | | | | | 24 |
| 2 | 1 | | | | | 25 |
| 25 | 1 | | | | | 26 |
| 22 | 1 | | | | | 27 |
| 13 | 1 | | | | | 28 |
| 45 | 10 | | | | | 29 |
| 14 | 1 | | | | | 30 |
| 24 | 2 | | | | | 31 |
| 6 | 1 | | | | | 32 |
| 11 | 5 | 3 | | | | 33 |
| 22 | 1 | | | | | 34 |
| 3 | 1 | | | | | 35 |
| 20 | 1 | | | | | 36 |
| 14 | 1 | | | | | 37 |
| 48 | 2 | | | | | 38 |
| 55 | 2 | | | | | 39 |
| 4 | 1 | | | | | 40 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

SUBSTATIONS

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

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | PANGUITCH SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 2 | PARIETTE SUBSTATION | DISTRIBUTION-UNATTEN | 69.00 | 24.90 | |
| 3 | PARK CITY SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 4 | PARKWAY SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 5 | PARLEYS SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 6 | PELICAN POINT SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 7 | PINE CANYON SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 8 | PINE CREEK SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 9 | PINNACLE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 10 | PLAIN CITY SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 11 | PLEASANT GROVE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 12 | PLEASANT VIEW SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 13 | PORTER ROCKWELL SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 14 | PROMONTORY SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 15 | QUAIL CREEK SUB | DISTRIBUTION-UNATTEN | 34.50 | 12.47 | |
| 16 | QUARRY SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 17 | QUITCHAPA SUB | DISTRIBUTION-UNATTEN | 34.50 | 12.47 | |
| 18 | RAINS SUB | DISTRIBUTION-UNATTEN | 46.00 | 7.20 | |
| 19 | RANDOLPH SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 20 | RASMUSON SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 21 | RATTLESNAKE SUB | DISTRIBUTION-UNATTEN | 69.00 | 24.90 | |
| 22 | RED MOUNTAIN SUB | DISTRIBUTION-UNATTEN | 69.00 | 34.50 | |
| 23 | RED ROCK SUB | DISTRIBUTION-UNATTEN | 69.00 | 4.16 | |
| 24 | REDWOOD SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 25 | RESEARCH PARK SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 26 | RICH SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 27 | RICHFIELD SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 28 | RICHMOND SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 29 | RIDGELAND SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 30 | RITER SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 31 | ROCK CANYON SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 32 | ROCKVILLE SUB | DISTRIBUTION-UNATTEN | 34.50 | 12.47 | |
| 33 | ROCKY POINT | DISTRIBUTION-UNATTEN | 138.00 | 13.20 | |
| 34 | ROSE PARK SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 35 | ROYAL SUB | DISTRIBUTION-UNATTEN | 46.00 | 4.16 | |
| 36 | SALINA SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 37 | SANDY SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 38 | SARATOGA SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 39 | SCIPIO SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 40 | SCOFIELD RESERVOIR SUB | DISTRIBUTION-UNATTEN | 46.00 | 7.20 | |

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)<br>(f) | Number of Transformers In Service<br>(g) | Number of Spare Transformers<br>(h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT<br>Type of Equipment<br>(i) | Number of Units<br>(j) | Total Capacity (In MVa)<br>(k) | Line No. |
| --- | --- | --- | --- | --- | --- | --- |
| 5 | 1 | | | | | 1 |
| 4 | 3 | | | | | 2 |
| 35 | 2 | | | | | 3 |
| 50 | 2 | | | | | 4 |
| 16 | 2 | | | | | 5 |
| 6 | 1 | | | | | 6 |
| 20 | 1 | | | | | 7 |
| 2 | 1 | | | | | 8 |
| 14 | 1 | | | | | 9 |
| 22 | 1 | | | | | 10 |
| 25 | 1 | | | | | 11 |
| 14 | 1 | | | | | 12 |
| 30 | 1 | | | | | 13 |
| 2 | 1 | | | | | 14 |
| 4 | 1 | | | | | 15 |
| 60 | 2 | | | | | 16 |
| 4 | 1 | | | | | 17 |
| 15 | 1 | | | | | 18 |
| 2 | 1 | | | | | 19 |
| 1 | 3 | | | | | 20 |
| 14 | 1 | | | | | 21 |
| 13 | 1 | | | | | 22 |
| 3 | 1 | | | | | 23 |
| 45 | 2 | | | | | 24 |
| 45 | 2 | | | | | 25 |
| 5 | 1 | | | | | 26 |
| 22 | 2 | | | | | 27 |
| 11 | 1 | | | | | 28 |
| 40 | 2 | | | | | 29 |
| 20 | 1 | | | | | 30 |
| 5 | 1 | | | | | 31 |
| 4 | 1 | | | | | 32 |
| 30 | 1 | | | | | 33 |
| 24 | 3 | | | | | 34 |
| | 3 | | | | | 35 |
| 11 | 1 | | | | | 36 |
| 60 | 2 | | | | | 37 |
| 30 | 1 | | | | | 38 |
| 1 | 3 | | | | | 39 |
| | 1 | | | | | 40 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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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 | SCOFIELD SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 2 | SECOND STREET SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 3 | SEVEN MILE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 4 | SHARON SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 5 | SHIVWITS SUB | DISTRIBUTION-UNATTEN | 34.50 | 4.16 | |
| 6 | SIXTH SOUTH SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 7 | SKULL POINT SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 8 | SNARR SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 9 | SNOWVILLE SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 10 | SNYDERVILLE SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 11 | SOLDIER SUMMIT SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 12 | SOUTH JORDAN SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 13 | SOUTH MILFORD SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 14 | SOUTH MOUNTAIN SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 15 | SOUTH OGDEN SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 16 | SOUTH PARK SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 17 | SOUTH WEBER SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 18 | SOUTHEAST SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | 46.00 |
| 19 | SOUTHWEST SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 20 | SPANISH VALLEY SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 21 | SPRINGDALE SUB | DISTRIBUTION-UNATTEN | 34.50 | 12.47 | |
| 22 | ST. JOHNS SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 23 | STAIRS SUB | DISTRIBUTION-UNATTEN | 12.47 | 2.40 | |
| 24 | STANSBURY SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 25 | SUMMIT CREEK SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 26 | SUMMIT PARK SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 27 | SUNRISE SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 28 | SUPERIOR SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 29 | SUTHERLAND SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 30 | TAYLOR SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 31 | THIEF CREEK SUB | DISTRIBUTION-UNATTEN | 138.00 | 24.90 | |
| 32 | THIRD WEST SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 33 | THIRTEENTH SOUTH SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 34 | THOMPSON SUB | DISTRIBUTION-UNATTEN | 46.00 | 4.16 | |
| 35 | TOOELE DEPOT SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.50 | |
| 36 | TOQUERVILLE SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | 34.50 |
| 37 | TRI CITY SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 38 | TWENTYTHIRD STREET SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 39 | UINTAH SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 40 | UNION SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Number of Units (j) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 1 | 3 | | | | | 1 |
| 13 | 2 | | | | | 2 |
| 5 | 3 | | | | | 3 |
| 20 | 1 | | | | | 4 |
| 6 | 1 | | | | | 5 |
| 20 | 1 | | | | | 6 |
| 2 | 1 | | | | | 7 |
| 40 | 2 | | | | | 8 |
| 5 | 1 | | | | | 9 |
| 30 | 1 | | | | | 10 |
| 13 | 1 | | | | | 11 |
| 30 | 1 | | | | | 12 |
| 20 | 2 | | | | | 13 |
| 60 | 2 | | | | | 14 |
| 25 | 1 | | | | | 15 |
| 14 | 1 | | | | | 16 |
| 50 | 1 | | | | | 17 |
| 50 | 2 | | | | | 18 |
| 22 | 2 | | | | | 19 |
| 6 | 1 | | | | | 20 |
| 4 | 1 | | | | | 21 |
| 4 | 1 | | | | | 22 |
| 2 | 1 | | | | | 23 |
| 20 | 1 | | | | | 24 |
| 14 | 1 | | | | | 25 |
| 7 | 1 | | | | | 26 |
| 30 | 1 | | | | | 27 |
| 8 | 1 | | | | | 28 |
| 6 | 1 | | | | | 29 |
| 14 | 1 | | | | | 30 |
| 14 | 1 | | | | | 31 |
| 40 | 2 | | | | | 32 |
| 24 | 3 | | | | | 33 |
| 2 | 1 | | | | | 34 |
| 25 | 1 | | | | | 35 |
| 34 | 2 | | | | | 36 |
| 30 | 1 | | | | | 37 |
| 13 | 1 | | | | | 38 |
| 39 | 2 | | | | | 39 |
| 50 | 2 | | | | | 40 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## SUBSTATIONS

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

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | UNIVERSITY SUB | DISTRIBUTION-UNATTEN | 46.00 | 4.16 | |
| 2 | VALLEY CENTER SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 3 | VERMILLION SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 4 | VERNAL SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 5 | VEYO HYDRO | DISTRIBUTION-UNATTEN | 34.50 | 2.40 | |
| 6 | VICKERS SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 7 | VINEYARD SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 8 | WALLSBURG SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 9 | WALNUT GROVE SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.50 | |
| 10 | WARREN SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 11 | WASATCH STATE PARK SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 12 | WASHAKIE SUB | DISTRIBUTION-UNATTEN | 138.00 | 4.16 | |
| 13 | WELBY SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 14 | WELFARE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 15 | WELLINGTON SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 16 | WEST COMMERCIAL SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 17 | WEST JORDAN SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 18 | WEST OGDEN SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 19 | WEST ROY SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 20 | WEST TEMPLE SUB | DISTRIBUTION-UNATTEN | 46.00 | 4.16 | |
| 21 | WESTFIELD SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 22 | WESTWATER SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 23 | WHITE MESA SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 24 | WILLOWCREEK SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 25 | WILLOWRIDGE SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 26 | WINCHESTER HILLS SUB | DISTRIBUTION-UNATTEN | 34.50 | 12.47 | |
| 27 | WINKLEMAN SUB | DISTRIBUTION-UNATTEN | 46.00 | 7.20 | |
| 28 | WOLF CREEK SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 29 | WOOD CROSS SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 30 | WOODRUFF SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 31 | Total | | 20275.47 | 3723.42 | 184.97 |
| 32 | Number of Substations- 300 | | | | |
| 33 | | | | | |
| 34 | ANGEL SUB | T/D-UNATTENDED | 138.00 | 12.47 | 46.00 |
| 35 | BDO SUBSTATION | T/D-UNATTENDED | 138.00 | 12.47 | |
| 36 | BUTLERVILLE SUB | T/D-UNATTENDED | 138.00 | 46.00 | 12.47 |
| 37 | COTTONWOOD SUB | T/D-UNATTENDED | 138.00 | 12.47 | 46.00 |
| 38 | EMMA PARK SUBSTATION | T/D-UNATTENDED | 138.00 | 12.47 | |
| 39 | HALE SUB | T/D-UNATTENDED | 138.00 | 46.00 | 12.47 |
| 40 | HIGHLAND SUB | T/D-UNATTENDED | 138.00 | 12.47 | 46.00 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa)<br>(f) | Number of Transformers In Service<br>(g) | Number of Spare Transformers<br>(h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT<br>Type of Equipment<br>(i) | Number of Units<br>(j) | Total Capacity (In MVa)<br>(k) | Line No. |
|---|---|---|---|---|---|---|
| 48 | 4 | | | | | 1 |
| 22 | 1 | | | | | 2 |
| 3 | 1 | | | | | 3 |
| 33 | 2 | | | | | 4 |
| 2 | 3 | | | | | 5 |
| 2 | 1 | | | | | 6 |
| 25 | 1 | | | | | 7 |
| 13 | 1 | | | | | 8 |
| 30 | 1 | | | | | 9 |
| 30 | 1 | | | | | 10 |
| 2 | 3 | | | | | 11 |
| 14 | 1 | | | | | 12 |
| 22 | 1 | | | | | 13 |
| 5 | 1 | | | | | 14 |
| 4 | 1 | | | | | 15 |
| 22 | 1 | | | | | 16 |
| 28 | 1 | | | | | 17 |
| 30 | 1 | | | | | 18 |
| 25 | 1 | | | | | 19 |
| 60 | 3 | | | | | 20 |
| 20 | 1 | | | | | 21 |
| 1 | 3 | | | | | 22 |
| 14 | 1 | | | | | 23 |
| 6 | 1 | | | | | 24 |
| 14 | 1 | | | | | 25 |
| 4 | 1 | | | | | 26 |
| | 1 | | | | | 27 |
| 6 | 1 | | | | | 28 |
| 20 | 1 | | | | | 29 |
| 2 | 1 | | | | | 30 |
| 5354 | 435 | 4 | | | | 31 |
| | | | | | | 32 |
| | | | | | | 33 |
| 135 | 3 | | | | | 34 |
| 30 | 1 | | | | | 35 |
| 175 | 3 | | | | | 36 |
| 289 | 7 | | | | | 37 |
| 8 | 1 | | | | | 38 |
| 114 | 2 | | | | | 39 |
| 97 | 2 | | | | | 40 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## SUBSTATIONS

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

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | JORDAN SUB | T/D-UNATTENDED | 138.00 | 46.00 | 12.47 |
| 2 | JUDGE SUB | T/D-UNATTENDED | 46.00 | 12.47 | |
| 3 | MCCLELLAND SUB | T/D-UNATTENDED | 138.00 | 46.00 | 12.47 |
| 4 | OQUIRRH SUB | T/D-UNATTENDED | 138.00 | 46.00 | 12.47 |
| 5 | PARRISH SUB | T/D-UNATTENDED | 138.00 | 12.47 | 46.00 |
| 6 | PIONEER PLANT | T/D-UNATTENDED | 138.00 | 2.30 | 46.00 |
| 7 | RIVERDALE SUB | T/D-UNATTENDED | 138.00 | 46.00 | 12.47 |
| 8 | SEVIER SUB | T/D-UNATTENDED | 138.00 | 46.00 | 12.47 |
| 9 | SILVER CREEK SUB | T/D-UNATTENDED | 138.00 | 12.47 | 46.00 |
| 10 | SPHINX SUB | T/D-UNATTENDED | 46.00 | 12.47 | |
| 11 | SYRACUSE SUB | T/D-UNATTENDED | 138.00 | 46.00 | 12.47 |
| 12 | TAYLORSVILLE SUB | T/D-UNATTENDED | 138.00 | 46.00 | 12.47 |
| 13 | TERMINAL | T/D-UNATTENDED | 345.00 | 12.47 | 46.00 |
| 14 | TIMP SUB | T/D-UNATTENDED | 138.00 | 46.00 | 12.47 |
| 15 | TOOELE SUB | T/D-UNATTENDED | 138.00 | 46.00 | 12.47 |
| 16 | WEST VALLEY SUB | T/D-UNATTENDED | 138.00 | 12.47 | |
| 17 | Total | | 3197.00 | 645.47 | 459.17 |
| 18 | Number of Substations- 23 | | | | |
| 19 | | | | | |
| 20 | BLUNDELL PLANT | TRANSMISSION-ATTEND | 46.00 | 12.47 | |
| 21 | CARBON PLANT | TRANSMISSION-ATTEND | 138.00 | 13.80 | |
| 22 | EMERY SUB | TRANSMISSION-ATTEND | 138.00 | 6.90 | 69.00 |
| 23 | GADSBY PLANT | TRANSMISSION-ATTEND | 138.00 | 13.80 | 46.00 |
| 24 | GADSBY SUB | TRANSMISSION-ATTEND | 138.00 | 46.00 | |
| 25 | HUNTER PLANT | TRANSMISSION-ATTEND | 345.00 | 23.00 | |
| 26 | HUNTINGTON PLANT | TRANSMISSION-ATTEND | 345.00 | 23.00 | |
| 27 | 90TH SOUTH SUB | TRANSMISSION-UNATTEN | 345.00 | 138.00 | |
| 28 | ABAJO SUB | TRANSMISSION-UNATTEN | 138.00 | 69.00 | |
| 29 | ASHLEY SUB | TRANSMISSION-UNATTEN | 138.00 | 46.00 | |
| 30 | BARNEY SUB | TRANSMISSION-UNATTEN | 138.00 | 46.00 | |
| 31 | BEN LOMOND SUB | TRANSMISSION-UNATTEN | 345.00 | 230.00 | 138.00 |
| 32 | BLACKHAWK SUB | TRANSMISSION-UNATTEN | 138.00 | 69.00 | 46.00 |
| 33 | BOOKCLIFFS SUB | TRANSMISSION-UNATTEN | 69.00 | 46.00 | |
| 34 | CAMERON SUB | TRANSMISSION-UNATTEN | 138.00 | 46.00 | |
| 35 | CAMP WILLIAMS SUB | TRANSMISSION-UNATTEN | 345.00 | 138.00 | 12.47 |
| 36 | CARBON SUB | TRANSMISSION-UNATTEN | 46.00 | 2.40 | |
| 37 | COLUMBIA SUB | TRANSMISSION-UNATTEN | 138.00 | 46.00 | |
| 38 | CRANER FLAT SUB | TRANSMISSION-UNATTEN | 138.00 | 12.47 | |
| 39 | CUTLER SUB | TRANSMISSION-UNATTEN | 138.00 | 46.00 | |
| 40 | EL MONTE SUB | TRANSMISSION-UNATTEN | 138.00 | 46.00 | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 164 | 2 | | | | | 1 |
| 22 | 1 | | | | | 2 |
| 340 | 4 | | | | | 3 |
| 135 | 3 | | | | | 4 |
| 97 | 2 | | | | | 5 |
| 51 | 7 | | | | | 6 |
| 180 | 3 | | | | | 7 |
| 34 | 4 | | | | | 8 |
| 100 | 2 | | | | | 9 |
| 3 | 4 | 3 | | | | 10 |
| 600 | 5 | | | | | 11 |
| 358 | 4 | | | | | 12 |
| 1108 | 6 | 2 | | | | 13 |
| 130 | 2 | | | | | 14 |
| 158 | 3 | | | | | 15 |
| 30 | 1 | | | | | 16 |
| 4358 | 72 | 5 | | | | 17 |
| | | | | | | 18 |
| | | | | | | 19 |
| 25 | 1 | | | | | 20 |
| 225 | 5 | | | | | 21 |
| 783 | 13 | 1 | | | | 22 |
| 568 | 17 | | | | | 23 |
| 318 | 2 | | | | | 24 |
| 1513 | 5 | 1 | | | | 25 |
| 981 | 4 | | | | | 26 |
| 1538 | 6 | 1 | | | | 27 |
| 67 | 1 | | | | | 28 |
| 133 | 2 | | | | | 29 |
| 100 | 1 | | | | | 30 |
| 1813 | 5 | | | | | 31 |
| 100 | 2 | | | | | 32 |
| 6 | 3 | 1 | | | | 33 |
| 25 | 3 | | | | | 34 |
| 169 | 2 | | | | | 35 |
| 8 | 1 | | | | | 36 |
| 33 | 1 | | | | | 37 |
| 40 | 2 | | | | | 38 |
| 70 | 2 | | | | | 39 |
| 313 | 3 | | | | | 40 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## SUBSTATIONS

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

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | GARKANE SUB | TRANSMISSION-UNATTEN | 69.00 | 46.00 | |
| 2 | GREEN CANYON SUB | TRANSMISSION-UNATTEN | 138.00 | 46.00 | |
| 3 | GRINDING SUB | TRANSMISSION-UNATTEN | 138.00 | 13.80 | |
| 4 | HELPER SUB | TRANSMISSION-UNATTEN | 138.00 | 46.00 | |
| 5 | HONEYVILLE SUB | TRANSMISSION-UNATTEN | 138.00 | 46.00 | |
| 6 | HORSESHOE SUB | TRANSMISSION-UNATTEN | 138.00 | 46.00 | 12.47 |
| 7 | HUNTINGTON SUB | TRANSMISSION-UNATTEN | 345.00 | 138.00 | 69.00 |
| 8 | JERUSALEM SUB | TRANSMISSION-UNATTEN | 138.00 | 46.00 | |
| 9 | LAMPO SUB | TRANSMISSION-UNATTEN | 138.00 | 46.00 | |
| 10 | MCFADDEN SUB | TRANSMISSION-UNATTEN | 138.00 | 46.00 | |
| 11 | MIDDLETON SUB | TRANSMISSION-UNATTEN | 138.00 | 69.00 | 34.50 |
| 12 | MIDVALLEY SUB | TRANSMISSION-UNATTEN | 345.00 | 138.00 | |
| 13 | MIDWAY CITY SUB | TRANSMISSION-UNATTEN | 138.00 | 46.00 | |
| 14 | MINERAL PRODUCTS SUB | TRANSMISSION-UNATTEN | 69.00 | 46.00 | |
| 15 | MOAB SUB | TRANSMISSION-UNATTEN | 138.00 | 69.00 | |
| 16 | NEBO SUB | TRANSMISSION-UNATTEN | 138.00 | 46.00 | |
| 17 | OLMSTED SUB | TRANSMISSION-UNATTEN | 46.00 | 2.40 | |
| 18 | PAROWAN VALLEY SUB | TRANSMISSION-UNATTEN | 230.00 | 138.00 | 34.50 |
| 19 | PAVANT SUB | TRANSMISSION-UNATTEN | 230.00 | 46.00 | |
| 20 | PINTO SUB | TRANSMISSION-UNATTEN | 345.00 | 138.00 | 69.00 |
| 21 | RED BUTTE SUB | TRANSMISSION-UNATTEN | 230.00 | 138.00 | |
| 22 | SAND COVE HYDRO | TRANSMISSION-UNATTEN | 34.50 | 2.40 | |
| 23 | SIGURD SUB | TRANSMISSION-UNATTEN | 345.00 | 230.00 | 138.00 |
| 24 | SMITHFIELD SUB | TRANSMISSION-UNATTEN | 138.00 | 46.00 | 12.47 |
| 25 | SPANISH FORK SUB | TRANSMISSION-UNATTEN | 345.00 | 138.00 | 46.00 |
| 26 | ST GEORGE SUB | TRANSMISSION-UNATTEN | 138.00 | 16.50 | |
| 27 | WEBER PLANT/SUB | TRANSMISSION-UNATTEN | 46.00 | 2.30 | |
| 28 | WEST CEDAR SUB | TRANSMISSION-UNATTEN | 230.00 | 138.00 | 34.50 |
| 29 | Total | | 8521.50 | 3089.24 | 761.91 |
| 30 | Number of Substations- 49 | | | | |
| 31 | | | | | |
| 32 | Washington | | | | |
| 33 | ATTALIA SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 34 | BOWMAN SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 35 | CASCADE KRAFT SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | 4.16 |
| 36 | CLINTON SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 37 | DAYTON SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 38 | DODD ROAD SUB | DISTRIBUTION-UNATTEN | 69.00 | 20.80 | |
| 39 | GRANDVIEW SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | 69.00 |
| 40 | HOPLAND SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT | | | Line No. |
|---|---|---|---|---|---|---|
| | | | Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | |
| 33 | 1 | | | | | 1 |
| 67 | 2 | | | | | 2 |
| 225 | 3 | | | | | 3 |
| 142 | 2 | | | | | 4 |
| 35 | 1 | | | | | 5 |
| 80 | 2 | | | | | 6 |
| 270 | 4 | | | | | 7 |
| 67 | 1 | | | | | 8 |
| 75 | 1 | | | | | 9 |
| 45 | 1 | | | | | 10 |
| 141 | 4 | | | | | 11 |
| 900 | 2 | | | | | 12 |
| 67 | 1 | | | | | 13 |
| 13 | 1 | | | | | 14 |
| 67 | 1 | | | | | 15 |
| 68 | 2 | | | | | 16 |
| 15 | 1 | | | | | 17 |
| 138 | 2 | | | | | 18 |
| 133 | 2 | | | | | 19 |
| 258 | 3 | | | | | 20 |
| 400 | 1 | | | | | 21 |
| | 1 | | | | | 22 |
| 1124 | 6 | | | | | 23 |
| 63 | 2 | | | | | 24 |
| 1017 | 5 | | | | | 25 |
| 100 | 3 | 1 | | | | 26 |
| 7 | 1 | | | | | 27 |
| 131 | 2 | | | | | 28 |
| 14509 | 139 | 5 | | | | 29 |
| | | | | | | 30 |
| | | | | | | 31 |
| | | | | | | 32 |
| 25 | 1 | | | | | 33 |
| 45 | 2 | | | | | 34 |
| 117 | 6 | | | | | 35 |
| 25 | 1 | | | | | 36 |
| 23 | 2 | | | | | 37 |
| 25 | 4 | | | | | 38 |
| 56 | 2 | | | | | 39 |
| 50 | 2 | | | | | 40 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
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| Line No. | Name and Location of Substation<br>(a) | Character of Substation<br>(b) | VOLTAGE (In MVa)<br>Primary<br>(c) | Secondary<br>(d) | Tertiary<br>(e) |
|---|---|---|---|---|---|
| 1 | MILL CREEK SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 2 | NACHES HYDRO | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 3 | NOB HILL SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 4 | NORTH PARK SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 5 | ORCHARD SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 6 | PACIFIC SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 7 | POMEROY SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 8 | PROSPECT POINT SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 9 | PUNKIN CENTER SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 10 | RIVER ROAD SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 11 | SELAH SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 12 | SULPHUR CREEK SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 13 | SUNNYSIDE SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 14 | TIETON SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | 34.50 |
| 15 | TOPPENISH SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 16 | TOUCHET SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 17 | VOELKER SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 18 | WAITSBURG SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 19 | WAPATO SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 20 | WENAS SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 21 | WHITE SWAN SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 22 | WILEY SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 23 | Total | | 2990.00 | 382.43 | 107.66 |
| 24 | Number of Substations- 30 | | | | |
| 25 | | | | | |
| 26 | CENTRAL SUB | T/D-UNATTENDED | 69.00 | 12.47 | |
| 27 | UNION GAP SUB | T/D-UNATTENDED | 230.00 | 115.00 | 12.47 |
| 28 | Total | | 299.00 | 127.47 | 12.47 |
| 29 | Number of Substations- 2 | | | | |
| 30 | | | | | |
| 31 | CONDIT PLANT | TRANSMISSION-ATTEND | 69.00 | 2.30 | |
| 32 | MERWIN PLANT | TRANSMISSION-ATTEND | 115.00 | 13.20 | |
| 33 | YALE PLANT | TRANSMISSION-ATTEND | 230.00 | 13.80 | |
| 34 | OUTLOOK SUB | TRANSMISSION-UNATTEN | 230.00 | 115.00 | |
| 35 | PASCO SUB | TRANSMISSION-UNATTEN | 115.00 | 69.00 | 7.20 |
| 36 | POMONA HEIGHTS SUB | TRANSMISSION-UNATTEN | 230.00 | 115.00 | |
| 37 | SWIFT 1 PLANT | TRANSMISSION-UNATTEN | 230.00 | 13.00 | |
| 38 | WALLA WALLA 230KV SUB | TRANSMISSION-UNATTEN | 230.00 | 69.00 | |
| 39 | WALLULA SUB | TRANSMISSION-UNATTEN | 230.00 | 69.00 | |
| 40 | Total | | 1679.00 | 479.30 | 7.20 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 45 | 2 | | | | | 1 |
| 20 | 1 | | | | | 2 |
| 42 | 2 | | | | | 3 |
| 45 | 2 | | | | | 4 |
| 50 | 2 | | | | | 5 |
| 28 | 3 | | | | | 6 |
| 9 | 1 | | | | | 7 |
| 40 | 2 | | | | | 8 |
| 20 | 2 | | | | | 9 |
| 51 | 4 | | | | | 10 |
| 45 | 2 | | | | | 11 |
| 25 | 1 | | | | | 12 |
| 45 | 2 | | | | | 13 |
| 29 | 2 | | | | | 14 |
| 50 | 2 | | | | | 15 |
| 6 | 1 | | | | | 16 |
| 25 | 1 | | | | | 17 |
| 9 | 1 | | | | | 18 |
| 45 | 2 | | | | | 19 |
| 25 | 2 | | | | | 20 |
| 22 | 2 | | | | | 21 |
| 45 | 2 | | | | | 22 |
| 1087 | 61 | | | | | 23 |
| | | | | | | 24 |
| | | | | | | 25 |
| 14 | 1 | | | | | 26 |
| 348 | 5 | | | | | 27 |
| 362 | 6 | | | | | 28 |
| | | | | | | 29 |
| | | | | | | 30 |
| 13 | 6 | 1 | | | | 31 |
| 183 | 9 | 1 | | | | 32 |
| 144 | 3 | 1 | | | | 33 |
| 125 | 1 | | | | | 34 |
| 39 | 9 | | | | | 35 |
| 300 | 2 | | | | | 36 |
| 261 | 3 | 1 | | | | 37 |
| 300 | 2 | | | | | 38 |
| 120 | 2 | | | | | 39 |
| 1485 | 37 | 4 | | | | 40 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original (2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## SUBSTATIONS

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

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | Number of Substations- 9 | | | | |
| 2 | | | | | |
| 3 | Wyoming | | | | |
| 4 | AIR BASE | DISTRIBUTION-UNATTEN | 12.47 | 2.40 | |
| 5 | ANTELOPE MINE | DISTRIBUTION-UNATTEN | 230.00 | 34.50 | |
| 6 | ASTLE STREET | DISTRIBUTION-UNATTEN | 34.50 | 13.20 | |
| 7 | BAILEY DOME SUB | DISTRIBUTION-UNATTEN | 57.00 | 12.47 | |
| 8 | BAR X SUB | DISTRIBUTION-UNATTEN | 230.00 | 34.50 | |
| 9 | BID MUDDY SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 10 | BIG PINEY SUB | DISTRIBUTION-UNATTEN | 69.00 | 24.90 | |
| 11 | BLACKS FORK | DISTRIBUTION-UNATTEN | 230.00 | 34.50 | |
| 12 | BRIDGER PUMP SUB | DISTRIBUTION-UNATTEN | 230.00 | 34.50 | 13.20 |
| 13 | BRYAN SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 14 | BUFFALO TOWN SUB | DISTRIBUTION-UNATTEN | 20.80 | 4.16 | |
| 15 | BYRON SUB | DISTRIBUTION-UNATTEN | 34.50 | 4.16 | |
| 16 | CASSA SUB | DISTRIBUTION-UNATTEN | 57.00 | 20.80 | |
| 17 | CENTER STREET SUB | DISTRIBUTION-UNATTEN | 115.00 | 4.16 | |
| 18 | CHAPMAN SUBSTATION | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 19 | CHATHAM SUB | DISTRIBUTION-UNATTEN | 34.50 | 4.16 | |
| 20 | CHUKAR SUB | DISTRIBUTION-UNATTEN | 12.47 | 4.16 | |
| 21 | CHURCH AND DWIGHT SUB | DISTRIBUTION-UNATTEN | 34.50 | 0.48 | |
| 22 | COKEVILLE SUB | DISTRIBUTION-UNATTEN | 46.00 | 24.90 | |
| 23 | COLUMBIA-GENEVA SUB | DISTRIBUTION-UNATTEN | 230.00 | 13.80 | |
| 24 | COMMUNITY PARK SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 25 | CROOKS GAP SUB | DISTRIBUTION-UNATTEN | 34.50 | 12.47 | |
| 26 | DEER CREEK SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 27 | DJ COAL MINE SUB | DISTRIBUTION-UNATTEN | 69.00 | 34.50 | |
| 28 | DOUGLAS SUB | DISTRIBUTION-UNATTEN | 57.00 | 2.30 | |
| 29 | DRY FORK SUB | DISTRIBUTION-UNATTEN | 69.00 | 4.16 | |
| 30 | ELK BASIN SUB | DISTRIBUTION-UNATTEN | 34.50 | 7.20 | |
| 31 | ELK HORN SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.50 | |
| 32 | EMIGRANT SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 33 | EVANS SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 34 | EVANSTON SUB | DISTRIBUTION-UNATTEN | 138.00 | 12.47 | |
| 35 | FARMERS UNION SUB | DISTRIBUTION-UNATTEN | 34.50 | 4.16 | |
| 36 | FIREHOLE SUB | DISTRIBUTION-UNATTEN | 230.00 | 34.50 | |
| 37 | FORT CASPER SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 38 | FORT SANDERS SUB | DISTRIBUTION-UNATTEN | 115.00 | 13.20 | |
| 39 | FRANNIE SUB | DISTRIBUTION-UNATTEN | 230.00 | 34.50 | |
| 40 | FRONTIER SUB | DISTRIBUTION-UNATTEN | 69.00 | 4.16 | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa)<br>(f) | Number of Transformers In Service<br>(g) | Number of Spare Transformers<br>(h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT<br>Type of Equipment<br>(i) | Number of Units<br>(j) | Total Capacity (In MVa)<br>(k) | Line No. |
|---|---|---|---|---|---|---|
| | | | | | | 1 |
| | | | | | | 2 |
| | | | | | | 3 |
| 1 | 3 | | | | | 4 |
| 25 | 1 | | | | | 5 |
| 13 | 1 | | | | | 6 |
| 2 | 1 | | | | | 7 |
| 25 | 1 | | | | | 8 |
| 7 | 1 | | | | | 9 |
| 8 | 1 | | | | | 10 |
| 150 | 2 | | | | | 11 |
| 73 | 4 | | | | | 12 |
| 25 | 1 | | | | | 13 |
| 2 | 3 | | | | | 14 |
| 2 | 3 | | | | | 15 |
| 2 | 6 | 1 | | | | 16 |
| 13 | 1 | | | | | 17 |
| 4 | 1 | | | | | 18 |
| | 3 | | | | | 19 |
| 1 | 3 | | | | | 20 |
| 3 | 2 | | | | | 21 |
| 4 | 1 | | | | | 22 |
| 45 | 2 | | | | | 23 |
| 40 | 2 | | | | | 24 |
| 5 | 3 | | | | | 25 |
| 9 | 1 | | | | | 26 |
| 13 | 1 | | | | | 27 |
| 6 | 3 | | | | | 28 |
| 9 | 1 | | | | | 29 |
| 5 | 1 | | | | | 30 |
| 25 | 1 | | | | | 31 |
| 13 | 1 | | | | | 32 |
| 9 | 1 | | | | | 33 |
| 40 | 2 | | | | | 34 |
| 2 | 3 | | | | | 35 |
| 50 | 2 | | | | | 36 |
| 25 | 1 | | | | | 37 |
| 20 | 1 | | | | | 38 |
| 50 | 2 | | | | | 39 |
| 6 | 1 | | | | | 40 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/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 | GARLAND SUB | DISTRIBUTION-UNATTEN | 230.00 | 34.50 | |
| 2 | GLENDO SUB | DISTRIBUTION-UNATTEN | 57.00 | 4.16 | |
| 3 | GRASS CREEK SUB | DISTRIBUTION-UNATTEN | 230.00 | 34.50 | |
| 4 | GREAT DIVIDE SUB | DISTRIBUTION-UNATTEN | 115.00 | 34.50 | |
| 5 | GREYBULL SUB | DISTRIBUTION-UNATTEN | 34.50 | 4.16 | |
| 6 | HANNA SUB | DISTRIBUTION-UNATTEN | 34.50 | 12.47 | |
| 7 | JACKALOPE SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 8 | KEMMERER SUB | DISTRIBUTION-UNATTEN | 69.00 | 24.90 | |
| 9 | KIRBY CREEK PUMPING STATION | DISTRIBUTION-UNATTEN | 34.50 | 2.40 | |
| 10 | KIRBY CREEK SUB | DISTRIBUTION-UNATTEN | 34.50 | 4.16 | |
| 11 | LANDER SUB | DISTRIBUTION-UNATTEN | 34.50 | 12.47 | |
| 12 | LARAMIE SUB | DISTRIBUTION-UNATTEN | 115.00 | 13.20 | |
| 13 | LATHAM SUB | DISTRIBUTION-UNATTEN | 230.00 | 34.50 | |
| 14 | LINCH SUB | DISTRIBUTION-UNATTEN | 69.00 | 13.80 | |
| 15 | LITTLE MOUNTAIN SUB | DISTRIBUTION-UNATTEN | 230.00 | 34.50 | |
| 16 | LOVELL SUB | DISTRIBUTION-UNATTEN | 34.50 | 4.16 | |
| 17 | MANDERSON SUB | DISTRIBUTION-UNATTEN | 34.50 | 4.16 | |
| 18 | MILL IRON SUB | DISTRIBUTION-UNATTEN | 34.50 | 13.80 | |
| 19 | MILLS SUB | DISTRIBUTION-UNATTEN | 12.47 | 4.16 | |
| 20 | MURPHY DOME SUB | DISTRIBUTION-UNATTEN | 34.50 | 13.20 | |
| 21 | NUGGETT SUB | DISTRIBUTION-UNATTEN | 69.00 | 7.20 | |
| 22 | OPAL SUB | DISTRIBUTION-UNATTEN | 46.00 | 24.90 | |
| 23 | ORIN SUB | DISTRIBUTION-UNATTEN | 57.00 | 12.47 | |
| 24 | ORPHA SUB | DISTRIBUTION-UNATTEN | 57.00 | 7.20 | |
| 25 | PARCO SUB | DISTRIBUTION-UNATTEN | 34.50 | 12.47 | |
| 26 | PINEDALE SUB | DISTRIBUTION-UNATTEN | 69.00 | 24.90 | |
| 27 | PITCHFORK SUB | DISTRIBUTION-UNATTEN | 69.00 | 24.90 | |
| 28 | POINT OF ROCKS SUB | DISTRIBUTION-UNATTEN | 230.00 | 34.50 | |
| 29 | POISON SPIDER SUB | DISTRIBUTION-UNATTEN | 69.00 | 2.40 | |
| 30 | POLECAT SUB | DISTRIBUTION-UNATTEN | 34.50 | 12.47 | |
| 31 | RAINBOW SUB | DISTRIBUTION-UNATTEN | 34.50 | 13.20 | |
| 32 | RAVEN SUB | DISTRIBUTION-UNATTEN | 230.00 | 34.50 | |
| 33 | RED BUTTE SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 34 | REFINERY SUB | DISTRIBUTION-UNATTEN | 115.00 | 12.47 | |
| 35 | SAGE HILL SUB | DISTRIBUTION-UNATTEN | 34.50 | 13.20 | |
| 36 | SHOSHONI SUB | DISTRIBUTION-UNATTEN | 34.50 | 2.40 | |
| 37 | SLATE CREEK SUB | DISTRIBUTION-UNATTEN | 69.00 | 12.47 | |
| 38 | SOUTH CODY SUB | DISTRIBUTION-UNATTEN | 69.00 | 24.90 | |
| 39 | SOUTH ELK BASIN SUB | DISTRIBUTION-UNATTEN | 34.50 | 4.16 | |
| 40 | SOUTH TRONA SUB | DISTRIBUTION-UNATTEN | 230.00 | 34.50 | |

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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.
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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 Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 45 | 2 | | | | | 1 |
| 3 | 4 | | | | | 2 |
| 25 | 1 | | | | | 3 |
| 20 | 1 | | | | | 4 |
| 3 | 1 | | | | | 5 |
| 6 | 1 | | | | | 6 |
| 25 | 1 | | | | | 7 |
| 10 | 1 | | | | | 8 |
| 3 | 3 | | | | | 9 |
| 2 | 3 | | | | | 10 |
| 25 | 2 | | | | | 11 |
| 50 | 2 | | | | | 12 |
| 25 | 1 | | | | | 13 |
| 13 | 1 | | | | | 14 |
| 20 | 1 | | | | | 15 |
| 4 | 3 | | | | | 16 |
| 1 | 3 | | | | | 17 |
| 13 | 1 | 1 | | | | 18 |
| 1 | 3 | | | | | 19 |
| 5 | 1 | | | | | 20 |
| | 1 | | | | | 21 |
| 8 | 1 | | | | | 22 |
| 2 | 3 | | | | | 23 |
| 3 | 3 | | | | | 24 |
| 5 | 1 | | | | | 25 |
| 8 | 1 | | | | | 26 |
| 17 | 9 | 2 | | | | 27 |
| 25 | 1 | | | | | 28 |
| 3 | 1 | | | | | 29 |
| 2 | 3 | | | | | 30 |
| 13 | 1 | | | | | 31 |
| 200 | 2 | | | | | 32 |
| 20 | 1 | | | | | 33 |
| 45 | 2 | | | | | 34 |
| 6 | 1 | | | | | 35 |
| 2 | 3 | | | | | 36 |
| 1 | 1 | | | | | 37 |
| 14 | 3 | 1 | | | | 38 |
| 2 | 6 | | | | | 39 |
| 150 | 2 | | | | | 40 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
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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 | SPRING CREEK SUB | DISTRIBUTION-UNATTEN | 115.00 | 13.20 | |
| 2 | SVILAR SUB | DISTRIBUTION-UNATTEN | 34.50 | 4.16 | |
| 3 | TEN MILE STEP DOWN SUB | DISTRIBUTION-UNATTEN | 34.50 | 12.50 | |
| 4 | TEN MILE SUB | DISTRIBUTION-UNATTEN | 69.00 | 34.50 | |
| 5 | THERMOPOLIS TOWN SUB | DISTRIBUTION-UNATTEN | 34.50 | 4.16 | |
| 6 | THUNDER CREEK SUB | DISTRIBUTION-UNATTEN | 57.00 | 12.47 | |
| 7 | VETERANS SUB | DISTRIBUTION-UNATTEN | 34.50 | 13.20 | |
| 8 | WELCH SUB | DISTRIBUTION-UNATTEN | 57.00 | 2.40 | |
| 9 | WERTZ-SINCLAIR SUB | DISTRIBUTION-UNATTEN | 57.00 | 4.16 | 12.50 |
| 10 | WEST ADAMS SUB | DISTRIBUTION-UNATTEN | 34.50 | 4.16 | |
| 11 | WESTERN CLAY SUB | DISTRIBUTION-UNATTEN | 34.50 | 0.48 | |
| 12 | WESTVACO SUB | DISTRIBUTION-UNATTEN | 230.00 | 34.50 | |
| 13 | WORLAND TOWN SUB | DISTRIBUTION-UNATTEN | 34.50 | 4.16 | |
| 14 | WYOPO SUB | DISTRIBUTION-UNATTEN | 230.00 | 34.50 | |
| 15 | WYUTA SUB | DISTRIBUTION-UNATTEN | 46.00 | 12.47 | |
| 16 | Total | | 8034.71 | 1382.50 | 25.70 |
| 17 | Number of Substations- 92 | | | | |
| 18 | | | | | |
| 19 | BUFFALO SUB | T/D-UNATTENDED | 230.00 | 20.80 | |
| 20 | HILLTOP SUB | T/D-UNATTENDED | 115.00 | 34.50 | 20.80 |
| 21 | LABARGE SUB | T/D-UNATTENDED | 69.00 | 24.90 | |
| 22 | RIVERTON 230 SUB | T/D-UNATTENDED | 230.00 | 12.47 | 34.50 |
| 23 | YELLOWCAKE SUB | T/D-UNATTENDED | 230.00 | 34.50 | |
| 24 | Total | | 874.00 | 127.17 | 55.30 |
| 25 | Number of Substations- 5 | | | | |
| 26 | | | | | |
| 27 | DAVE JOHNSTON PLANT/SUB | TRANSMISSION-ATTEND | 230.00 | 115.00 | 69.00 |
| 28 | JIM BRIDGER 345KV SUB | TRANSMISSION-ATTEND | 345.00 | 230.00 | 34.50 |
| 29 | JIM BRIDGER UNITS 1-4 | TRANSMISSION-ATTEND | 345.00 | 22.00 | |
| 30 | NAUGHTON SUB | TRANSMISSION-ATTEND | 230.00 | 69.00 | |
| 31 | WYODAK 230KV SUB | TRANSMISSION-ATTEND | 230.00 | 69.00 | |
| 32 | WYODAK PLANT | TRANSMISSION-ATTEND | 230.00 | 22.00 | |
| 33 | BAIROIL SUB | TRANSMISSION-UNATTEN | 115.00 | 34.50 | 57.00 |
| 34 | CASPER SUB | TRANSMISSION-UNATTEN | 230.00 | 115.00 | 69.00 |
| 35 | CHAPPELL CREEK SUB | TRANSMISSION-UNATTEN | 230.00 | 69.00 | |
| 36 | FOOTE CREEK WIND FARM | TRANSMISSION-UNATTEN | 230.00 | 34.50 | |
| 37 | GLENDO AUTO SUB | TRANSMISSION-UNATTEN | 69.00 | 57.00 | |
| 38 | MANSFACE SUB | TRANSMISSION-UNATTEN | 230.00 | 34.50 | |
| 39 | MIDWEST SUB | TRANSMISSION-UNATTEN | 230.00 | 69.00 | 34.50 |
| 40 | MINERS SUB | TRANSMISSION-UNATTEN | 230.00 | 115.00 | 34.50 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 25 | 1 | | | | | 1 |
| 2 | 3 | | | | | 2 |
| 5 | 1 | | | | | 3 |
| 13 | 1 | | | | | 4 |
| 5 | 1 | | | | | 5 |
| 9 | 1 | | | | | 6 |
| 25 | 2 | | | | | 7 |
| 3 | 3 | | | | | 8 |
| 2 | 6 | | | | | 9 |
| 3 | 1 | | | | | 10 |
| 1 | 1 | | | | | 11 |
| 25 | 1 | | | | | 12 |
| 5 | 1 | | | | | 13 |
| 20 | 1 | 1 | | | | 14 |
| | 1 | | | | | 15 |
| 1700 | 175 | 6 | | | | 16 |
| | | | | | | 17 |
| | | | | | | 18 |
| 20 | 1 | | | | | 19 |
| 45 | 2 | 1 | | | | 20 |
| 8 | 6 | | | | | 21 |
| 50 | 3 | | | | | 22 |
| 25 | 1 | | | | | 23 |
| 148 | 13 | 1 | | | | 24 |
| | | | | | | 25 |
| | | | | | | 26 |
| 1358 | 17 | | | | | 27 |
| 1084 | 22 | | | | | 28 |
| 1122 | 2 | | | | | 29 |
| 1232 | 15 | 1 | | | | 30 |
| 60 | 1 | | | | | 31 |
| 503 | 3 | 1 | | | | 32 |
| 53 | 3 | | | | | 33 |
| 517 | 6 | | | | | 34 |
| 67 | 1 | | | | | 35 |
| 196 | 2 | | | | | 36 |
| 15 | 2 | | | | | 37 |
| 20 | 1 | | | | | 38 |
| 91 | 4 | | | | | 39 |
| 58 | 4 | 1 | | | | 40 |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

## SUBSTATIONS

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

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | MUSTANG SUB | TRANSMISSION-UNATTEN | 230.00 | 115.00 | |
| 2 | OREGON BASIN SUB | TRANSMISSION-UNATTEN | 230.00 | 34.50 | 69.00 |
| 3 | PLATTE SUB | TRANSMISSION-UNATTEN | 230.00 | 115.00 | 34.50 |
| 4 | RAILROAD SUB | TRANSMISSION-UNATTEN | 230.00 | 138.00 | |
| 5 | ROCK SPRINGS 230 SUB | TRANSMISSION-UNATTEN | 230.00 | 34.50 | |
| 6 | SAGE SUB | TRANSMISSION-UNATTEN | 69.00 | 46.00 | |
| 7 | THERMOPOLIS SUB | TRANSMISSION-UNATTEN | 230.00 | 115.00 | |
| 8 | YELLOWTAIL SUB | TRANSMISSION-UNATTEN | 230.00 | 161.00 | |
| 9 | Total | | 4853.00 | 1814.50 | 402.00 |
| 10 | Number of Substations- 22 | | | | |
| 11 | | | | | |
| 12 | CALIFORNIA | | | | |
| 13 | Distribution - 45 | | | | |
| 14 | T/D - 3 | | | | |
| 15 | Transmission - 9 | | | | |
| 16 | | | | | |
| 17 | IDAHO | | | | |
| 18 | Distribution - 67 | | | | |
| 19 | T/D - 4 | | | | |
| 20 | Transmission - 19 | | | | |
| 21 | | | | | |
| 22 | OREGON | | | | |
| 23 | Distribution - 181 | | | | |
| 24 | T/D - 10 | | | | |
| 25 | Transmission - 41 | | | | |
| 26 | | | | | |
| 27 | UTAH | | | | |
| 28 | Distribution - 300 | | | | |
| 29 | T/D - 23 | | | | |
| 30 | Transmission - 49 | | | | |
| 31 | | | | | |
| 32 | WASHINGTON | | | | |
| 33 | Distribution - 30 | | | | |
| 34 | T/D - 2 | | | | |
| 35 | Transmission - 9 | | | | |
| 36 | | | | | |
| 37 | WYOMING | | | | |
| 38 | Distribution - 92 | | | | |
| 39 | T/D - 5 | | | | |
| 40 | Transmission - 22 | | | | |

| Name of Respondent<br>PacifiCorp | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>03/31/2009 | Year/Period of Report<br>End of 2008/Q4 |
|---|---|---|---|

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa)<br>(f) | Number of Transformers In Service<br>(g) | Number of Spare Transformers<br>(h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT<br>Type of Equipment<br>(i) | Number of Units<br>(j) | Total Capacity (In MVa)<br>(k) | Line No. |
|---|---|---|---|---|---|---|
| 200 | 2 | | | | | 1 |
| 65 | 2 | | | | | 2 |
| 165 | 4 | | | | | 3 |
| 400 | 1 | | | | | 4 |
| 50 | 2 | | | | | 5 |
| 22 | 1 | | | | | 6 |
| 175 | 2 | | | | | 7 |
| 100 | 1 | | | | | 8 |
| 7553 | 98 | 3 | | | | 9 |
| | | | | | | 10 |
| | | | | | | 11 |
| | | | | | | 12 |
| 344 | | | | | | 13 |
| 129 | | | | | | 14 |
| 696 | | | | | | 15 |
| | | | | | | 16 |
| | | | | | | 17 |
| 799 | | | | | | 18 |
| 314 | | | | | | 19 |
| 3342 | | | | | | 20 |
| | | | | | | 21 |
| | | | | | | 22 |
| 4438 | | | | | | 23 |
| 1238 | | | | | | 24 |
| 6413 | | | | | | 25 |
| | | | | | | 26 |
| | | | | | | 27 |
| 5354 | | | | | | 28 |
| 4358 | | | | | | 29 |
| 14509 | | | | | | 30 |
| | | | | | | 31 |
| | | | | | | 32 |
| 1087 | | | | | | 33 |
| 362 | | | | | | 34 |
| 1485 | | | | | | 35 |
| | | | | | | 36 |
| | | | | | | 37 |
| 1700 | | | | | | 38 |
| 148 | | | | | | 39 |
| 7553 | | | | | | 40 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## SUBSTATIONS

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

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | | | | | |
| 2 | ALL STATES | | | | |
| 3 | Distribution - 715 | | | | |
| 4 | T/D - 47 | | | | |
| 5 | Transmission - 149 | | | | |
| 6 | | | | | |
| 7 | | | | | |
| 8 | | | | | |
| 9 | | | | | |
| 10 | | | | | |
| 11 | | | | | |
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| 40 | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PacifiCorp | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/2009 | End of 2008/Q4 |

## SUBSTATIONS (Continued)

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

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

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| | | | | | | 1 |
| | | | | | | 2 |
| 13722 | | | | | | 3 |
| 6549 | | | | | | 4 |
| 33998 | | | | | | 5 |
| | | | | | | 6 |
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| | | | | | | 40 |

***Schedule Page: 426.9 Line No.: 24 Column: a***

The Dixonville 500kV Substation is jointly owned by the respondent and the Bonneville Power Adminstration ("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: 426.9 Line No.: 36 Column: a***

The Meridian 500kV Substation is jointly owned by the respondent and the Bonneville Power Adminstration ("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.: 28 Column: a***

The Jim Bridger 345kV Substation is jointly owned by the respondent and Idaho Power Company. Ownership of the substation is as follow: PacifiCorp 66.7%, Idaho Power Company 33.3%. Operation and maintance costs are shared between the two parties and responsibility is as follow: PacifiCorp 66.7%. and Idaho Power Company 33.3%.

## INDEX

| Schedule | Page No. |
|---|---|

| Schedule | Page No. |
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ANNUAL REPORT

IDAHO SUPPLEMENT TO FERC FORM NO. 1
FOR
MULTI-STATE ELECTRIC COMPANIES

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IDAHO PUBLIC
UTILITIES COMMISSION

INDEX

| Name of Respondent | This Report Is: | Date of Report | Year of Report |
|---|---|---|---|
| PacifiCorp<br>dba Rocky Mountain Power | (1) _X_ An Original<br>(2) __ A resubmission | (Mo, Da, Yr)<br>May 12, 2009 | Dec. 31, 2008 |

# STATE OF IDAHO STATEMENT OF OPERATING INCOME FOR THE YEAR

| Line No. | ACCOUNT (a) | (Ref) Page No. (b) | ELECTRIC UTILITY Current Year (c) | ELECTRIC UTILITY Previous Year (d) |
|---|---|---|---|---|
| 1 | UTILITY OPERATING INCOME | | | |
| 2 | Operating Revenues (400) | 2 | 255,576,999 | 245,796,394 |
| 3 | Operating Expenses | | | |
| 4 | Operation Expenses (401) | 3-6 | 157,693,957 | 154,454,090 |
| 5 | Maintenance Expenses (402) | 3-6 | 20,302,529 | 21,753,903 |
| 6 | Depreciation Expenses (403) | 7 | 22,141,858 | 24,741,880 |
| 7 | Amort. & Depl. of Utility Plant (404-405) | 7 | 2,155,279 | 2,634,326 |
| 8 | Amort. of Utility Plant Acq. Adj (406) | | 318,186 | 350,390 |
| 9 | Amort. of Property Losses, Unrecovered Plant and Regulatory Study Costs (407) | | 336,221 | 200,703 |
| 10 | Amort. of Conversion Expenses (407) | | - | - |
| 11 | Taxes other Than Income Taxes (408.1) | 8 | 4,904,875 | 4,657,065 |
| 12 | Income Taxes - Federal (409.1) | | (4,773,615) | 4,093,241 |
| 13 | -Other (409.1) | | (417,772) | 604,267 |
| 14 | Provision for Deferred Income Taxes (410.1) | | 30,632,497 | 7,037,972 |
| 15 | Provision for Deferred Income Taxes - Cr. (411.1) | | (14,829,314) | (14,120,792) |
| 16 | Investment Tax Credit Adj. - Net (411.4) | | (219,739) | (744,909) |
| 17 | (Gains) from Disp. of Utility Plant (411.6) | | - | - |
| 18 | Losses from Disp. of Utility Plant (411.7) | | - | - |
| 19 | (Gains) from Emission Allowances | | (315,306) | (965,806) |
| 20 | (Gains) Loss on Sale of Utility Plant | | (103,876) | 239,008 |
| 21 | TOTAL Utility Operating Expenses *(Enter Total of Lines 4 thru 20)* | | 217,825,780 | 214,935,338 |
| 22 | Net Utility Operating Income *(Enter Total of line 2 less 21)* | | 37,751,219 | 30,861,056 |

| Name of Respondent | This Report Is: | Date of Report |
|---|---|---|
| PacifiCorp<br>dba Rocky Mountain Power | (1) _X_ An Original<br>(2) __ A resubmission | (Mo, Da, Yr)<br>May 12, 2009 |

## ELECTRIC OPERATING REVENUES (Account 400)

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
2. 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.
3. 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.
4. 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 Accoun footnote)
5. See pa 08-1 Changes During P and important rate
6. For lines 2,4,5,6 No. 1 for amounts accounts.
7. Include unmete sales in a footnote

| Line No. | Title of Account (a) | OPERATING REVENUES: Amount for Year (a) | OPERATING REVENUES: Amount for Previous Year (c) | MEGAWATT HOURS SOLD: Amount for Year (d) | MEGAWATT HOURS SOLD: Amount for Previous Year (e) | AVG. N Numb Ye (f |
|---|---|---|---|---|---|---|
| 1 | Sales of Electricity | | | | | |
| 2 | (440) Residential Sales | 58,451,721 | 49,527,597 | 727,371 | 710,522 | |
| 3 | (442) Commercial and Industrial Sales | | | | | |
| 4 | Small (or Commercial) (See Instr. 4) | 26,869,031 | 26,011,840 | 398,426 | 398,113 | |
| 5 | Large (or Industrial) (See Instr. 4) | 111,954,918 | 108,417,305 | 2,262,639 | 2,364,422 | |
| 6 | (444) Public Street and Highway Lighting | 467,242 | 243,091 | 2,488 | 2,215 | |
| 7 | (445) Other Sales to Public Authorities | - | - | - | - | |
| 8 | (446) Sales to Railroads and Railways | - | - | - | - | |
| 9 | (448) Interdepartmental Sales | - | - | - | - | |
| 10 | TOTAL Sales to Ultimate Consumers | 197,742,912 | 184,199,833 | 3,390,924 | 3,475,272 | |
| 11 | (447) Sales for Resale | 49,491,559 | 54,281,131 | (a) | (a) | (a |
| 12 | TOTAL Sales of Electricity | 247,234,471 | 238,480,964 | 3,390,924 | 3,475,272 | |
| 13 | (Less) (449.1) Provision for Rate Refunds | - | - | - | - | |
| 14 | TOTAL Revenue Net of Prov. For Refunds | 247,234,471 | 238,480,964 | 3,390,924 | 3,475,272 | |
| 15 | Other Operating Revenues | | | | | |
| 16 | (450) Forfeited Discounts | 458,582 | 368,639 | | | |
| 17 | (451) Miscellaneous Service Revenues | 161,100 | 142,972 | | | |
| 18 | (453) Sale of Water and Water Power | 1,533 | 6,873 | | | |
| 19 | (454) Rent from Electric Property | 808,980 | 713,252 | | | |
| 20 | (455) Interdepartmental Rents | - | - | | | |
| 21 | (456) Other Electric Revenues | 6,912,333 | 6,083,694 | | | |
| 22 | | | | | | |
| 23 | TOTAL Other Operating Revenues | 8,342,528 | 7,315,430 | | | |
| 24 | TOTAL Electric Operating Revenues | 255,576,999 | 245,796,394 | | | |

**(a) For a complete list of the number of custome 310-311 of the FERC Form No. 1 - Sales for Resal**

| Name of Respondent<br>PacifiCorp<br>dba Rocky Mountain Power | This Report Is:<br>(1) _X_ An Original<br>(2) __ A resubmission | Date of Report<br>(Mo, Da, Yr)<br>May 12, 2009 | Year of Report<br>Dec. 31, 2008 |
|---|---|---|---|

## ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES - IDAHO

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

| Line No. | Account (a) | Amount for Current Year (b) | Amount for Previous Year (c) |
|---|---|---|---|
| 1 | 1. POWER PRODUCTION EXPENSES | | |
| 2 | A. Steam Power Generation | | |
| 3 | Operation | | |
| 4 | (500) Operation Supervision and Engineering | 1,266,099 | 1,367,905 |
| 5 | (501) Fuel | 40,122,749 | 37,994,894 |
| 6 | (502) Steam Expenses | 2,170,220 | 2,147,813 |
| 7 | (503) Steam from Other Sources | 217,429 | 319,119 |
| 8 | (Less) (504) Steam Transferred - Cr. | - | - |
| 9 | (505) Electric Expenses | 247,630 | 248,882 |
| 10 | (506) Miscellaneous Steam Power Expenses | 2,525,521 | 2,666,853 |
| 11 | (507) Rents | 16,334 | 54,292 |
| 12 | TOTAL Operation (Enter Total of lines 4 thru 11) | 46,565,982 | 44,799,758 |
| 13 | Maintenance | | |
| 14 | (510) Maintenance Supervision and Engineering | 346,029 | 386,444 |
| 15 | (511) Maintenance of Structures | 1,440,505 | 1,434,887 |
| 16 | (512) Maintenance of Boiler Plant | 5,024,482 | 6,018,680 |
| 17 | (513) Maintenance of Electric Plant | 1,674,389 | 2,031,525 |
| 18 | (514) Maintenance of Miscellaneous Steam Plant | 735,467 | 749,911 |
| 19 | TOTAL Maintenance (Enter Total of lines 14 thru 18) | 9,220,872 | 10,621,447 |
| 20 | TOTAL Power Production Expenses - Steam Power (Enter Total of lines 12 & 19) | 55,786,854 | 55,421,205 |
| 21 | B. Nuclear Power Generation | | |
| 22 | Operation | | |
| 23 | (517) Operation Supervision and Engineering | - | - |
| 24 | (518) Fuel | - | - |
| 25 | (519) Coolants and Water | . | - |
| 26 | (520) Steam Expenses | - | - |
| 27 | (521) Steam from Other Sources | - | - |
| 28 | (Less) (522) Steam Transferred - Cr. | - | - |
| 29 | (523) Electric Expenses | - | - |
| 30 | (524) Miscellaneous Nuclear Power Expenses | - | - |
| 31 | (525) Rents | - | - |
| 32 | TOTAL Operation (Enter Total of lines 23 thru 31) | - | - |
| 33 | Maintenance | | |
| 34 | (528) Maintenance Supervision and Engineering | - | - |
| 35 | (529) Maintenance of Structures | - | - |
| 36 | (530) Maintenance of Reactor Plant Equipment | - | - |
| 37 | (531) Maintenance of Electric Plant | - | - |
| 38 | (532) Maintenance of Miscellaneous Nuclear Plant | - | - |
| 39 | TOTAL Maintenance (Enter Total of lines 34 thru 38) | - | - |
| 40 | TOTAL Power Production Expenses - Nuclear Power (Enter Total of lines 32 & 39) | - | - |
| 41 | C. Hydraulic Power Generation | | |
| 42 | Operation | | |
| 43 | (535) Operation Supervision and Engineering | 512,537 | 538,980 |
| 44 | (536) Water for Power | 17,502 | 13,863 |
| 45 | (537) Hydraulic Expenses | 237,533 | 300,934 |
| 46 | (538) Electric Expenses | - | - |
| 47 | (539) Miscellaneous Hydraulic Power Generation Expenses | 1,036,304 | 968,006 |
| 48 | (540) Rents | 8,202 | 2,905 |
| 49 | TOTAL Operation (Enter Total of lines 43 thru 48) | 1,812,078 | 1,824,688 |

| Name of Respondent<br>PacifiCorp<br>dba Rocky Mountain Power | This Report Is:<br>(1) _X_ An Original<br>(2) __ A resubmission | Date of Report<br>(Mo, Da, Yr)<br>May 12, 2009 | Year of Report<br><br>Dec. 31, 2008 |
|---|---|---|---|

## ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES - IDAHO

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

| Line No. | Account<br>(a) | Amount for Current Year<br>(b) | Amount for Previous Year<br>(c) |
|---|---|---|---|
| 50 | C. Hydraulic Power Generation (Continued) | | |
| 51 | Maintenance | | |
| 52 | (541) Maintenance Supervision and Engineering | 156 | - |
| 53 | (542) Maintenance of Structures | 71,146 | 65,285 |
| 54 | (543) Maintenance of Reservoirs, Dams, and Waterways | 83,463 | 65,092 |
| 55 | (544) Maintenance of Electric Plant | 91,322 | 107,335 |
| 56 | (545) Maintenance of Miscellaneous Hydraulic Plant | 124,953 | 134,793 |
| 57 | TOTAL Maintenance (Enter Total of lines 52 thru 56) | 371,040 | 372,505 |
| 58 | TOTAL Power Production Expenses - Hydraulic Power (Enter Total of lines 49 & 57) | 2,183,118 | 2,197,193 |
| 59 | D. Other Power Generation | | |
| 60 | Operation | | |
| 61 | (546) Operation Supervision and Engineering | 12,686 | 46,666 |
| 62 | (547) Fuel | 30,518,527 | 22,205,955 |
| 63 | (548) Generation Expenses | 1,053,278 | 1,540,082 |
| 64 | (549) Miscellaneous Other Power Generation Expenses | 635,509 | 379,302 |
| 65 | (550) Rents | 408,480 | 872,554 |
| 66 | TOTAL Operation (Enter Total of lines 61 thru 65) | 32,628,480 | 25,044,559 |
| 67 | Maintenance | | |
| 68 | (551) Maintenance Supervision and Engineering | - | - |
| 69 | (552) Maintenance of Structures | 75,393 | 42,092 |
| 70 | (553) Maintenance of Generation and Electric Plant | 346,580 | 308,564 |
| 71 | (554) Maintenance of Miscellaneous Other Power Generation Plant | 29,322 | 28,095 |
| 72 | TOTAL Maintenance (Enter Total of lines 68 thru 71) | 451,295 | 378,751 |
| 73 | TOTAL Power Production Expenses - Other Power (Enter Total of lines 66 & 72) | 33,079,775 | 25,423,310 |
| 74 | E. Other Power Supply Expenses | | |
| 75 | (555) Purchased Power | 45,333,059 | 45,203,486 |
| 76 | (556) System Control and Load Dispatching | 116,018 | 162,112 |
| 77 | (557) Other Expenses (1) | 7,644,461 | 9,345,032 |
| 78 | TOTAL Other Power Supply Expenses (Enter Total of lines 75 thru 77) | 53,093,538 | 54,710,630 |
| 79 | TOTAL Power Production Expenses - (Enter Total of lines 20, 40, 58, 73 and 78) | 144,143,285 | 137,752,338 |
| 80 | 2. TRANSMISSION EXPENSES | | |
| 81 | Operation | | |
| 82 | (560) Operation Supervision and Engineering | 453,452 | 524,839 |
| 83 | (561) Load Dispatching | 495,694 | 504,465 |
| 84 | (562) Station Expenses | 108,582 | 64,333 |
| 85 | (563) Overhead Line Expenses | 5,420 | 8,045 |
| 86 | (564) Underground Line Expenses | - | - |
| 87 | (565) Transmission of Electricity by Others | 7,060,389 | 6,819,746 |
| 88 | (566) Miscellaneous Transmission Expenses | 104,244 | 175,971 |
| 89 | (567) Rents | 47,772 | 86,730 |
| 90 | TOTAL Operation (Enter Total of lines 82 thru 89) | 8,275,553 | 8,184,129 |
| 91 | Maintenance | | |
| 92 | (568) Maintenance Supervision and Engineering | 570 | 3,596 |
| 93 | (569) Maintenance of Structures | 239,765 | 206,778 |
| 94 | (570) Maintenance of Station Equipment | 644,177 | 592,955 |
| 95 | (571) Maintenance of Overhead Lines | 941,024 | 852,025 |
| 96 | (572) Maintenance of Underground Lines | - | - |
| 97 | (573) Maintenance of Miscellaneous Transmission Plant | 27,906 | 24,336 |
| 98 | TOTAL Maintenance (Enter Total of lines 92 thru 97) | 1,853,442 | 1,679,690 |
| 99 | TOTAL Transmission Expenses (Enter Total of lines 90 and 98) | 10,128,995 | 9,863,819 |
| 100 | 3. DISTRIBUTION EXPENSES | | |
| 101 | Operation | | |
| 102 | (580) Operation Supervision and Engineering | 894,939 | 862,041 |
| 103 | (581) Load Dispatching | 595,952 | 583,812 |

(1) The Idaho amounts in FERC account 557 are $3,238,393 for Current Year and $3,851,417 for Previous Year. However, these amounts have been increased by $4,406,068 for Current Year and $5,493,615 for Previous Year because of the embedded cost differentials on Idaho results.

| Name of Respondent<br>PacifiCorp<br>dba Rocky Mountain Power | This Report Is:<br>(1) _X_ An Original<br>(2) __ A resubmission | Date of Report<br>(Mo, Da, Yr)<br>May 12, 2009 | Year of Report<br><br>Dec. 31, 2008 |
|---|---|---|---|

## ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES - IDAHO

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

| Line No. | Account (a) | Amount for Current Year (b) | Amount for Previous Year (c) |
|---|---|---|---|
| 104 | 3. DISTRIBUTION EXPENSES (Continued) | | |
| 105 | (582) Station Expenses | 255,140 | 174,616 |
| 106 | (583) Overhead Line Expenses | 162,592 | 197,205 |
| 107 | (584) Underground Line Expenses | - | - |
| 108 | (585) Street Lighting and Signal System Expenses | 10,351 | 11,443 |
| 109 | (586) Meter Expenses | 397,340 | 318,915 |
| 110 | (587) Customer Installations Expenses | 709,324 | 635,356 |
| 111 | (588) Miscellaneous Distribution Expenses | 370,170 | 500,303 |
| 112 | (589) Rents | 27,195 | 66,016 |
| 113 | TOTAL Operation (Enter Total of lines 102 thru 112) | 3,423,003 | 3,349,707 |
| 114 | Maintenance | | |
| 115 | (590) Maintenance Supervision and Engineering | 302,779 | 297,707 |
| 116 | (591) Maintenance of Structures | 118,918 | 96,189 |
| 117 | (592) Maintenance of Station Equipment | 664,135 | 435,314 |
| 118 | (593) Maintenance of Overhead Lines | 4,533,920 | 5,039,022 |
| 119 | (594) Maintenance of Underground Lines | 646,670 | 750,325 |
| 120 | (595) Maintenance of Line Transformers | 52,059 | 31,551 |
| 121 | (596) Maintenance of Street Lighting and Signal Systems | 163,040 | 165,812 |
| 122 | (597) Maintenance of Meters | 317,714 | 354,660 |
| 123 | (598) Maintenance of Miscellaneous Distribution Plant | 86,051 | 84,548 |
| 124 | TOTAL Maintenance (Enter Total of lines 115 thru 123) | 6,885,286 | 7,255,128 |
| 125 | TOTAL Distribution Expenses (Enter Total of lines 113 and 124) | 10,308,289 | 10,604,835 |
| 126 | 4. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES | | |
| 127 | Operation | | |
| 128 | (901) Supervision | 92,212 | 112,029 |
| 129 | (902) Meter Reading Expenses | 1,807,158 | 1,611,031 |
| 130 | (903) Customer Records and Collection Expenses | 2,155,564 | 2,226,795 |
| 131 | (904) Uncollectible Accounts | 303,856 | 308,510 |
| 132 | (905) Miscellaneous Customer Accounts Expenses | 8,556 | 15,055 |
| 133 | TOTAL Customer Accounts Expenses (Enter Total of lines 128 thru 132) | 4,367,346 | 4,273,420 |
| 134 | 5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES | | |
| 135 | Operation | | |
| 136 | (907) Supervision | 9,619 | 17,212 |
| 137 | (908) Customer Assistance Expenses | 1,565,402 | 3,710,798 |
| 138 | (909) Informational and Instructional Expenses | 154,192 | 139,899 |
| 139 | (910) Miscellaneous Customer Service and Informational Expenses | 2,476 | 751 |
| 140 | TOTAL Cust. Service and Informational Exp. (Enter Total of lines 136 thru 139) | 1,731,689 | 3,868,660 |
| 141 | 6. SALES EXPENSES | | |
| 142 | Operation | | |
| 143 | (911) Supervision | - | - |
| 144 | (912) Demonstrating and Selling Expenses | - | - |
| 145 | (913) Advertising Expenses | - | - |
| 146 | (916) Miscellaneous Sales Expenses | - | - |
| 147 | TOTAL Sales Expenses (Enter Total of lines 143 thru 146) | - | - |
| 148 | 7. ADMINISTRATIVE AND GENERAL EXPENSES | | |
| 149 | Operation | | |
| 150 | (920) Administrative and General Salaries | 1,953,895 | 4,938,066 |
| 151 | (921) Office Supplies and Expense | 700,062 | 758,491 |
| 152 | (Less) (922) Administrative Expenses Transferred - Cr. | (1,208,446) | (1,232,157) |
| 153 | (923) Outside Services Employee | 667,017 | 580,987 |
| 154 | (924) Property Insurance | 1,788,804 | 1,459,458 |
| 155 | (925) Injuries and Damages | 531,614 | 672,179 |
| 156 | (926) Employee Pensions and Benefits | - | - |
| 157 | | | |

| Name of Respondent | This Report Is: | Date of Report | Year of Report |
|---|---|---|---|
| PacifiCorp<br>dba Rocky Mountain Power | (1) _X_ An Original<br>(2) __ A resubmission | (Mo, Da, Yr)<br>May 12, 2009 | Dec. 31, 2008 |

## ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued) - IDAHO

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

| Line No. | Account<br>(a) | Amount for Current Year<br>(b) | Amount for Previous Year<br>(c) |
|---|---|---|---|
| 157 | 7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued) | | |
| 158 | (927) Franchise Requirements | - | - |
| 159 | (928) Regulatory Commission Expenses | 543,491 | 451,722 |
| 160 | (929) Duplicate Charges - Cr. | (223,706) | (347,978) |
| 161 | (930.1) General Advertising Expenses | - | - |
| 162 | (930.2) Miscellaneous General Expenses | 741,466 | 796,911 |
| 163 | (931) Rents | 302,091 | 320,860 |
| 164 | TOTAL Operation (Enter Total of lines 150 thru 163) | 5,796,288 | 8,398,539 |
| 165 | Maintenance | | |
| 166 | (935) Maintenance of General Plant | 1,520,594 | 1,446,382 |
| 167 | TOTAL Administrative and General Expenses (Enter Total of lines 164 & 166) | 7,316,882 | 9,844,921 |
| 168 | TOTAL Electric Operation and Maintenance Expenses (Enter Total of lines 79, 99, 125, 133, 140, 147, and 167) | 177,996,486 | 176,207,993 |

## SUMMARY OF ELECTRIC OPERATION AND MAINTENANCE EXPENSES - IDAHO

| Line No. | Functional Classifications<br>(a) | Operation<br>(b) | Maintenance<br>(c) | Total<br>(d) |
|---|---|---|---|---|
| 169 | Power Production Expenses | | | |
| 170 | Electric Generation: | | | |
| 171 | Steam Power | 46,565,982 | 9,220,872 | **55,786,854** |
| 172 | Nuclear Power | - | - | **-** |
| 173 | Hydraulic -Conventional | 1,812,078 | 371,040 | **2,183,118** |
| 174 | Other Power Generation | 32,628,480 | 451,295 | **33,079,775** |
| 175 | Other Power Supply Expenses | 53,093,538 | | **53,093,538** |
| 176 | Total Power Production Expenses | 134,100,078 | 10,043,207 | **144,143,285** |
| 177 | Transmission Expenses | 8,275,553 | 1,853,442 | **10,128,995** |
| 178 | Distribution Expenses | 3,423,003 | 6,885,286 | **10,308,289** |
| 179 | Customer Accounts Expenses | 4,367,346 | | **4,367,346** |
| 180 | Customer Service and Informational Expenses | 1,731,689 | | **1,731,689** |
| 181 | Sales Expenses | - | | **-** |
| 182 | Adm. and General Expenses | 5,796,288 | 1,520,594 | **7,316,882** |
| 183 | Total Electric Operation and Maintenance Expenses | 157,693,957 | 20,302,529 | **177,996,486** |

STATE OF IDAHO - ALLOCATED

| Name of Respondent | This Report Is: | Date of Report | Year of Report |
|---|---|---|---|
| PacifiCorp<br>dba Rocky Mountain Power | (1) _x_ An Original<br>(2) __ A resubmission | (Mo, Da, Yr)<br>May 12, 2009 | Dec. 31, 2008 |

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

### A. Summary of Depreciation and Amortization Charges

| Line No. | Functional Classification (a) | Depreciation Expense (Account 403) (b) | Amortization of Limited-Term Electric Plant (Acct. 404) (c) | Amortization of Other Electric Plant (Acct. 405) (d) | Total (e) |
|---|---|---|---|---|---|
| 1 | Intangible Plant | | 2,075,078 | | **2,075,078** |
| 2 | Steam Production Plant | 6,088,251 | | | **6,088,251** |
| 3 | Nuclear Production Plant | | | | **-** |
| 4 | Hydraulic Production Plant - Conventional | 869,767 | | | **869,767** |
| 5 | Hydraulic Production Plant - Pumped Storage | | | | **-** |
| 6 | Other Production Plant | 3,144,487 | 9,512 | | **3,153,999** |
| 7 | Transmission Plant | 3,381,714 | | | **3,381,714** |
| 8 | Distribution Plant | 6,441,986 | | | **6,441,986** |
| 9 | General Plant | 2,215,653 | 70,689 | | **2,286,342** |
| 10 | Common Plant - Electric | | | | **-** |
| 11 | TOTAL | 22,141,858 | 2,155,279 | - | **24,297,137** |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year of Report |
|---|---|---|---|
| PacifiCorp<br>dba Rocky Mountain Power | (1) _X_ An Original<br>(2) __ A resubmission | May 12, 2009 | Dec. 31, 2008 |

**STATE OF IDAHO - ALLOCATED**
**TAXES, OTHER THAN INCOME TAXES**
**ACCOUNT 408.1**

| | KIND OF TAX | AMOUNT |
|---|---|---|
| 1 | Property | 4,349,885 |
| 2 | Other | 554,990 |
| 3 | | |
| 4 | | |
| 5 | | |
| 6 | | |
| 7 | | |
| 8 | | |
| 9 | | |
| 10 | | |
| 11 | | |
| 12 | | |
| 13 | | |
| 14 | | |
| 15 | | |
| 16 | | |
| 17 | | |
| 18 | | |
| 19 | | |
| 20 | Total ( Must agree with page 1, line 11.) | 4,904,875 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year of |
|---|---|---|---|
| PacifiCorp<br>dba Rocky Mountain Power | (1) _X An Original<br>(2) __ A resubmission | May 12, 2009 | 31 |

**NON-UTILITILY PROPERTY (ACCOUNT 121)**

| | Location Description | Description | Beginning Balance (c) | Acquistion (d) | Retirement (e) | Tran (f |
|---|---|---|---|---|---|---|
| 1 | IDAHO FALLS POLE TREATING PLANT | Fee Land | 54,317 | | | |
| 2 | MALAD PLANT SITE AND WATER RIGHTS | Land Rights | 33 | | | |
| 3 | GEORGETOWN PLANT LAND (121) | Fee Land | 110 | | | |
| 4 | LAVA DEVELOPMENT (121) | Land Rights | 1,274 | | | |
| 5 | MENAN SUBSTATION SITE (121) | Fee Land | 55 | | | |
| 6 | UCON SITE (121) - CATERCORNER TO UCON SUBSTATI | Fee Land | 27 | | | |
| 7 | OLD DUBOIS SUBSTATION SITE | Fee Land | 75 | | | |
| 8 | EAST RIVER SUBSTATION SITE (121) | Fee Land | 13,742 | | | |
| 9 | NORTH MONTEVIEW SUBSTATION SITE (121) | Fee Land | 328 | | | |
| 10 | MONTEVIEW SUBSTATION SITE (121) | Fee Land | 618 | | | |
| 11 | MUD LAKE SERVICE CENTER | Fee Land | 17,915 | | | |
| 12 | ARCO TRANSMISSION SUBSTATION AND OFFICE | Fee Land | 1,740 | | | |
| 13 | ARCO TRANSMISSION SUBSTATION AND OFFICE | Structures | 38,071 | | (2,418) | |
| 14 | THREEMILE KNOLL SUBSTATION | Fee Land | 26,058 | | | |
| 15 | Total Non-Utility Property | | 154,363 | - | (2,418) | |

| Name of Respondent<br>PacifiCorp<br>dba Rocky Mountain Power | This Report Is:<br>(1) X An Original<br>(2) __ A resubmission | Date of Report<br>(Mo, Da, Yr)<br>May 12, 2009 | Year of Report<br><br>Dec. 31, 2008 |
|---|---|---|---|

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

| Line No. | Account (a) | Amount for Current Year (b) | Amount for Previous Year (c) |
|---|---|---|---|
| 1 | **UTILITY PLANT** | | |
| 2 | In Service | | |
| 3 | Plant In Service (Classified) | 955,902,116 | 937,383,729 |
| 4 | Property Under Capital Lease (1) | - | - |
| 5 | Plant Purchased or Sold | - | - |
| 6 | Completed Construction not Classified | 12,044,596 | 2,474,213 |
| 7 | Experimental Plant Unclassified | - | - |
| 8 | Total (Enter Total of Lines 3 through 7) | 967,946,712 | 939,857,942 |
| 9 | Leased To Others | - | - |
| 10 | Held for Future Use | 750,560 | 458,401 |
| 11 | Construction Work In Process | 67,820,539 | 56,067,228 |
| 12 | Acquisition Adjustments | 9,128,243 | 10,052,135 |
| 13 | Total Utility Plant (Enter Total of Lines 8 through 12) | 1,045,646,054 | 1,006,435,706 |
| 14 | Accumulated Provision for Depreciation, Amortization & Depletion | 389,746,293 | 401,323,912 |
| 15 | Net Utility Plant (Enter Total of Line 13 less Line 14) | 655,899,761 | 605,111,794 |
| 16 | **DETAIL OF ACCUMULATED PROVISION FOR DEPRECIATION, AMORTIZATION AND DEPLETION** | | |
| 17 | In Service | | |
| 18 | Depreciation | 363,401,052 | 374,363,449 |
| 19 | Amortization/Depletion of Producing Natural Gas Land And Land Rights | - | - |
| 20 | Amortization of Underground Storage Land and Land Rights | - | - |
| 21 | Amortization of Other Utility Plant | 21,228,818 | 21,676,585 |
| 22 | Total In Service (Enter Total of Lines 18 through 21) | 384,629,870 | 396,040,034 |
| 23 | Leased To Others | | |
| 24 | Depreciation | - | - |
| 25 | Amortization And Depletion | - | - |
| 26 | Total Leased to Others (Enter Total of Lines 24 and 25) | - | - |
| 27 | Held for Future Use | | |
| 28 | Depreciation | - | - |
| 29 | Amortization | - | - |
| 30 | Total Held for Future Use (Enter Total of Lines 28 and 29) | - | - |
| 31 | Abandonment of Leases (Natural Gas) | - | - |
| 32 | Accumulated Provision for Asset Acquisition Adjustment | 5,116,423 | 5,283,878 |
| 33 | Total Accumulated Provisions (Should Agree With Line 14 above) (Enter Total of Lines 22, 26, 30, 31 and 32) | 389,746,293 | 401,323,912 |
| 34 | | | |

(1) **Capital leases are not included in rate base; they are charged to operating expense.**

# ELECTRIC PLANT IN SERVICE - STATE OF IDAHO (ALLOCATED)

(In addition to Account 101, Electric Plant In Service (Classified), this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.)

1. Report below the original cost of electric plant in service according to prescribed accounts.

2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year.

3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.

| Line No. | Account (a) | Beginning Balance (b) | Balance at End of Year (g) |
|---|---|---|---|
| 1 | 1. INTANGIBLE PLANT | | |
| 2 | (301) Organization | - | - |
| 3 | (302) Franchises and Consents | 5,943,718 | 7,254,241 |
| 4 | (303) Miscellaneous Intangible Plant | 31,740,826 | 29,779,555 |
| 5 | TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4) | 37,684,544 | 37,033,796 |
| 6 | 2. PRODUCTION PLANT | | |
| 7 | A Steam Production Plant | | |
| 8 | (310) Land and Land Rights | 5,619,834 | 5,428,705 |
| 9 | (311) Structures and Improvements | 50,322,784 | 46,937,258 |
| 10 | (312) Boiler Plant Equipment | 178,106,232 | 168,618,554 |
| 11 | (313) Engines and Engine Driven Generators | - | - |
| 12 | (314) Turbogenerator Units | 47,429,029 | 45,180,197 |
| 13 | (315) Accessory Electric Equipment | 21,324,879 | 20,390,793 |
| 14 | (316) Misc. Power Plant Equipment | 1,703,496 | 1,515,785 |
| 15 | TOTAL Steam Production Plant (Enter Total of lines 8 thru 14) | 304,506,254 | 288,071,292 |
| 16 | B. Nuclear Production Plant | | |
| 17 | (320) Land and Land Rights | - | - |
| 18 | (321) Structures and Improvements | - | - |
| 19 | (322) Reactor Plant Equipment | - | - |
| 20 | (323) Turbogenerator Units | - | - |
| 21 | (324) Accessory Electric Equipment | - | - |
| 22 | (325) Misc. Power Plant Equipment | - | - |
| 23 | TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 22) | - | - |
| 24 | C. Hydraulic Production Plant | | |
| 25 | (330) Land and Land Rights | 1,256,223 | 1,143,555 |
| 26 | (331) Structures and Improvements | 5,314,359 | 4,958,440 |
| 27 | (332) Reservoirs, Dams, and Waterways | 18,099,144 | 16,727,953 |
| 28 | (333) Water Wheels, Turbines, and Generators | 5,709,495 | 5,616,447 |
| 29 | (334) Accessory Electric Equipment | 2,708,895 | 2,768,451 |
| 30 | (335) Misc. Power Plant Equipment | 164,450 | 143,508 |
| 31 | (336) Roads, Railroads, and Bridges | 882,435 | 829,230 |
| 32 | TOTAL Hydraulic Production Plant (Enter Total of lines 25 thru 31) | 34,135,001 | 32,187,584 |
| 33 | D. Other Production Plant | | |
| 34 | (340) Land and Land Rights | 1,377,583 | 1,250,990 |
| 35 | (341) Structures and Improvements | 5,222,382 | 6,419,904 |
| 36 | (342) Fuel Holders, Products, and Accessories | 1,249,415 | 536,054 |
| 37 | (343) Prime Movers | 46,456,479 | 73,560,400 |
| 38 | (344) Generators | 11,304,452 | 13,374,080 |
| 39 | (345) Accessory Electric Equipment | 4,834,781 | 7,296,653 |
| 40 | (346) Misc. Power Plant Equipment | 332,069 | 402,103 |
| 41 | TOTAL Other Production Plant (Enter Total of lines 34 thru 40) | 70,777,161 | 102,840,184 |
| 42 | TOTAL Production Plant (Enter Total of lines 15, 23, 32, and 41) | 409,418,416 | 423,099,060 |

| ELECTRIC PLANT IN SERVICE (Continued) STATE OF IDAHO (ALLOCATED) | | | |
|---|---|---|---|
| Line No. | Account<br>(a) | Beginning Balance<br>(b) | Balance End of Year<br>(g) |
| 43 | 3. TRANSMISSION PLANT | | |
| 44 | (350) Land and Land Rights | 5,940,329 | 5,478,889 |
| 45 | (352) Structures and Improvements | 3,804,817 | 3,901,893 |
| 46 | (353) Station Equipment | 63,622,797 | 63,172,280 |
| 47 | (354) Towers and Fixtures | 25,748,909 | 24,823,566 |
| 48 | (355) Poles and Fixtures | 33,174,956 | 30,966,465 |
| 49 | (356) Overhead Conductors and Devices | 43,393,835 | 41,007,286 |
| 50 | (357) Underground Conduit | 209,581 | 188,356 |
| 51 | (358) Underground Conductors and Devices | 468,101 | 431,335 |
| 52 | (359) Roads and Trails | 734,332 | 665,647 |
| 53 | TOTAL Transmission Plant (Enter Total of lines 44 thru 52) | 177,097,657 | 170,635,717 |
| 54 | 4. DISTRIBUTION PLANT | | |
| 55 | (360) Land and Land Rights | 1,253,969 | 1,255,542 |
| 56 | (361) Structures and Improvements | 797,057 | 1,151,317 |
| 57 | (362) Station Equipment | 22,780,426 | 26,123,899 |
| 58 | (363) Storage Battery Equipment | - | - |
| 59 | (364) Poles, Towers, and Fixtures | 53,860,274 | 56,159,120 |
| 60 | (365) Overhead Conductors and Devices | 32,451,572 | 32,973,127 |
| 61 | (366) Underground Conduit | 6,531,868 | 6,942,477 |
| 62 | (367) Underground Conductors and Devices | 21,443,864 | 22,642,301 |
| 63 | (368) Line Transformers | 59,350,458 | 62,062,240 |
| 64 | (369) Services | 23,816,753 | 25,683,819 |
| 65 | (370) Meters | 13,732,238 | 13,817,534 |
| 66 | (371) Installations on Customer Premises | 159,686 | 162,607 |
| 67 | (372) Leased Property on Customer Premises | 4,873 | 2,437 |
| 68 | (373) Street Lighting and Signal Systems | 570,172 | 592,483 |
| 69 | TOTAL Distribution Plant (Enter Total of lines 55 thru 68) | 236,753,210 | 249,568,903 |
| 70 | 5. GENERAL PLANT | | |
| 71 | (389) Land and Land Rights | 576,855 | 555,588 |
| 72 | (390) Structures and Improvements | 16,687,646 | 16,306,746 |
| 73 | (391) Office Furniture and Equipment | 5,950,035 | 5,217,332 |
| 74 | (392) Transportation Equipment | 6,445,558 | 6,437,195 |
| 75 | (393) Stores Equipment | 905,091 | 867,042 |
| 76 | (394) Tools, Shop and Garage Equipment | 3,526,756 | 3,430,881 |
| 77 | (395) Laboratory Equipment | 2,069,457 | 2,041,070 |
| 78 | (396) Power Operated Equipment | 8,696,096 | 8,750,317 |
| 79 | (397) Communication Equipment | 14,267,752 | 14,367,405 |
| 80 | (398) Miscellaneous Equipment | 331,588 | 339,542 |
| 81 | SUBTOTAL (Enter Total of lines 71 thru 80) | 59,456,834 | 58,313,118 |
| 82 | (399) Other Tangible Property | 16,973,068 | 17,251,522 |
| 83 | TOTAL General Plant (Enter Total of lines 81 thru 82) | 76,429,902 | 75,564,640 |
| 84 | TOTAL (Accounts 101) | 937,383,729 | 955,902,116 |
| 85 | (102) Electric Plant Purchased | - | - |
| 86 | Plant Sold | - | - |
| 87 | (103) Experimental Electric Plant Unclassified | - | - |
| 88 | (106) Plant Unclassified | 2,474,213 | 12,044,596 |
| 89 | TOTAL Electric Plant in Service | 939,857,942 | 967,946,712 |

| Name of Respondent | This Report Is: | Date of Report | Year of Report |
|---|---|---|---|
| PacifiCorp<br>dba Rocky Mountain Power | (1) _X_ An Original<br>(2) __ A resubmission | (Mo, Da, Yr)<br>May 12, 2009 | Dec. 31, 2008 |

## MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.

2. Give an explanation of important inventory adjustments during the year (on a supplemental page) showing general classes of material and supplies and the various accounts (operating expense, clearing accounts, plant, etc.) affected - debited or credited. Show separately debits or credits to stores expense clearing, if applicable.

| Line No. | ACCOUNT (a) | Balance Beginning of Year (b) | Balance End of Year (c) | Department or Departments Which Use Material (d) |
|---|---|---|---|---|
| 1 | Fuel Stock (Account 151) | [redacted] | 7,402,116 | Electric |
| 2 | Fuel Stock Expenses Undistributed (Account 152) | [redacted] | | |
| 3 | Residuals and Extracted Products (Account 153) | [redacted] | | |
| 4 | Plant Materials and Operating Supplies (Account 154) | [redacted] | | |
| 5 | Assigned to - Construction (Estimated) | [redacted] | | |
| 6 | Assigned to - Operations and Maintenance | [redacted] | | |
| 7 | Production Plant (Estimated) | [redacted] | 4,755,711 | Electric |
| 8 | Transmission Plant (Estimated) | [redacted] | 136,982 | Electric |
| 9 | Distribution Plant (Estimated) | [redacted] | 4,429,074 | Electric |
| 10 | Assigned to - Other | [redacted] | 1,589 | Electric |
| 11 | TOTAL Account 154 (Enter Total of lines 5 thru 10) | [redacted] | 9,323,356 | |
| 12 | Merchandise (Account 155) | [redacted] | | |
| 13 | Other Materials and Supplies (Account 156) | [redacted] | | |
| 14 | Nuclear Materials Held for Sale (Account 157) (Not applicable to Gas Utilities) | [redacted] | | |
| 15 | Stores Expense Undistributed (Account 163) | [redacted] | | |
| 16 | | [redacted] | | |
| 17 | | [redacted] | | |
| 18 | | [redacted] | | |
| 19 | | [redacted] | | |
| 20 | TOTAL Materials and Supplies (Per Balance Sheet) | [redacted] | 16,725,472 | |