PAC-E

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

RECEIVED

2016 MAY 31 AM 10: 14

IDAHO PUBLIC UTILITIES COMMISSION

1407 West North Temple, Suite 310
Salt Lake City, Utah 84116

May 27, 2016

VIA OVERNIGHT DELIVERY

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

Attention: Jean D. Jewell
Commission Secretary

RE: FERC Form 1

PacifiCorp (d.b.a. Rocky Mountain Power) submits for filing one copy of PacifiCorp's annual FERC Form 1 report for the year ended December 31, 2015.

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

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

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

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

Sincerely,

Jeffrey K. Larsen

Jeffrey K. Larsen
Vice President, Regulation

Enclosure

THIS FILING IS	
Item 1: ☒ An Initial (Original) Submission	OR ☐ Resubmission No. ____

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

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

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

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
PacifiCorp	**End of** 2015/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 PacifiCorp	02 Year/Period of Report End of 2015/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 Street, Suite 1900, Portland, OR 97232	
05 Name of Contact Person Mark Staehnke	06 Title of Contact Person External Reporting Director
07 Address of Contact Person *(Street, City, State, Zip Code)* 825 N.E. Multnomah Street, Suite 1900, Portland, OR 97232	

08 Telephone of Contact Person,*Including Area Code* (503) 813-5784	09 This Report Is (1) ☒ An Original (2) ☐ A Resubmission	10 Date of Report *(Mo, Da, Yr)* / /

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 Nikki L. Kobliha	03 Signature Nikki L. Kobliha	04 Date Signed *(Mo, Da, Yr)* 04/12/2016
02 Title 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 (2) [ ] A Resubmission	/ /	End of 2015/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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	N/A
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	N/A
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	N/A
25	Unrecovered Plant and Regulatory Study Costs	230	N/A
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	N/A
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	N/A
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	N/A
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	N/A
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	
65	Pumped Storage Generating Plant Statistics	408-409	N/A
66	Generating Plant Statistics Pages	410-411	

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [X] Two copies will be submitted [ ] No annual report to stockholders is prepared		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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.

Nikki L. Kobliha, Vice President and Chief Financial Officer
825 N.E. Multnomah Street, Suite 1900
Portland, OR 97232

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.

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 is a United States regulated electric utility company headquartered in Oregon that serves 1.8 million retail electric customers, including residential, commercial, industrial, irrigation and other customers in portions of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp is principally engaged in the business of generating, transmitting, distributing and buying and selling electricity on the wholesale market with other utilities, energy marketing companies, financial institutions and other market participants. 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. Transmission related functions and Energy Imbalance Market activities are operated under the trade name PacifiCorp Transmission.

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

Schedule Page: 101 Line No.: 1 Column: Item 2

PacifiCorp was initially incorporated in 1910 under the laws of the state of Maine under the name Pacific Power & Light Company. In 1984, Pacific Power & Light Company changed its name to PacifiCorp. In 1989, it merged with Utah Power and Light Company, a Utah corporation, in a transaction wherein both corporations merged into a newly formed Oregon corporation. The resulting Oregon corporation was re-named PacifiCorp, which is the operating entity today.

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.(a)
- Berkshire Hathaway Energy Company ("BHE") (100%)
  - PPW Holdings LLC (100% controlled by BHE)
    - PacifiCorp (100% of common stock held by PPW Holdings LLC)

(a) Berkshire Hathaway Inc. owns 89.9%, Walter Scott, Jr. (along with family members and related entities) owns 9.1% and Gregory E. Abel owns 1.0% of BHE's common stock.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	Energy West Mining Company	Mining	100	
2	Fossil Rock Fuels, LLC	Mining	100	
3	Glenrock Coal Company	Mining	100	
4	Interwest Mining Company	Management Services	100	
5	Pacific Minerals, Inc.	Management Services	100	
6	Bridger Coal Company	Mining	66.67	
7	Trapper Mining Inc.	Mining	21.40	
8	PacifiCorp Foundation	Non-profit foundation		
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Schedule Page: 103 Line No.: 1 Column: a

Energy West Mining Company provided coal-mining services to PacifiCorp utilizing PacifiCorp's assets until mining operations ceased in 2015. Energy West Mining Company's costs are fully absorbed by PacifiCorp.

Schedule Page: 103 Line No.: 3 Column: a

Glenrock Coal Company ceased mining operations in 1999.

Schedule Page: 103 Line No.: 5 Column: a

Pacific Minerals, Inc. is a wholly owned subsidiary of PacifiCorp that holds a 66.67% ownership interest in Bridger Coal Company.

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

Bridger Coal Company is a coal mining joint venture with Idaho Energy Resources Company, a subsidiary of Idaho Power Company, and is jointly controlled by Pacific Minerals, Inc. and Idaho Energy Resources Company.

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

PacifiCorp is a minority owner in Trapper Mining Inc., a cooperative. The members are Salt River Project Agricultural Improvement and Power District (32.10%), Tri-State Generation and Transmission Association, Inc. (26.57%), PacifiCorp (21.40%) and Platte River Power Authority (19.93%).

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

The PacifiCorp Foundation is an independent non-profit foundation created by PacifiCorp in 1988. The PacifiCorp Foundation operates as the Rocky Mountain Power Foundation and the Pacific Power Foundation. As of December 31, 2015, all of PacifiCorp Foundation's three directors are also directors of PacifiCorp.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	Chairman of the Board of Directors		
2	and Chief Executive Officer	Gregory E. Abel	
3	President and Chief Executive Officer, Pacific Power	Stefan A. Bird	313,275
4	President and Chief Executive Officer,		
5	Rocky Mountain Power	Cindy A. Crane	324,028
6	President and Chief Executive Officer,		
7	PacifiCorp Transmission	R. Patrick Reiten	330,000
8	Vice President and Chief Financial Officer	Nikki L. Kobliha	177,384
9	Former President and Chief Executive Officer,		
10	PacifiCorp Energy	Micheal G. Dunn	68,750
11	Former Senior Vice President and CFO,		
12	PacifiCorp	Douglas K. Stuver	163,394
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FOOTNOTE DATA

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

PacifiCorp sets forth the salary information for its "named executive officers" for the year ended December 31, 2015, consistent with Item 402 of Regulation S-K promulgated by the Securities and Exchange Commission, in PacifiCorp's Annual Report on Form 10-K. Salary information of other officers will be provided to the Federal Energy Regulatory Commission 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

Gregory E. Abel receives no direct compensation from PacifiCorp. PacifiCorp reimburses Berkshire Hathaway Energy Company, ("BHE") for the cost of Mr. Abel’s time spent on matters supporting PacifiCorp, including compensation paid to him by BHE, pursuant to an intercompany administrative services agreement among BHE and its subsidiaries. Please refer to BHE’s Annual Report on Form 10-K for the year ended December 31, 2015 for executive compensation information for Mr. Abel.

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

Stefan A. Bird was elected President and Chief Executive Officer ("CEO") of Pacific Power effective March 10, 2015. Refer to Item 13 in Important Changes During the Year in this Form No. 1.

Schedule Page: 104 Line No.: 7 Column: b

R. Patrick Reiten, the former President and CEO of Pacific Power, was elected President and CEO of PacifiCorp Transmission effective March 10, 2015. Refer to Item 13 in Important Changes During the Year in this Form No. 1.

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

Nikki L. Kobliha was appointed Vice President and Chief Financial Officer ("CFO") of PacifiCorp effective August 13, 2015 and was elected to that position on October 26, 2015. Refer to Item 13 in Important Changes During the Year in this Form No. 1.

Schedule Page: 104 Line No.: 10 Column: b

Micheal G. Dunn, former President and CEO of PacifiCorp Energy, resigned as a director and employee effective March 2015. Refer to Item 13 in Important Changes During the Year in this Form No. 1.

Schedule Page: 104 Line No.: 12 Column: b

Douglas K. Stuver resigned as an employee and Senior Vice President and CFO of PacifiCorp effective August 13, 2015. Refer to Item 13 in Important Changes During the Year in this Form No. 1.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	PacifiCorp Board of Directors as of December 31, 2015:	
2	Gregory E. Abel	
3	(Chairman of the Board of Directors and CEO, PacifiCorp)	666 Grand Avenue, 29th Floor, Des Moines, Iowa 50309
4	Stefan A. Bird	
5	(President and CEO, Pacific Power)	825 NE Multnomah, Suite 2000, Portland, Oregon 97232
6	Cindy A. Crane	
7	(President and CEO, Rocky Mountain Power)	1407 West North Temple, Suite 310, Salt Lake City, Utah 84116
8	R. Patrick Reiten	
9	(President and CEO, PacifiCorp Transmission)	825 NE Multnomah, Suite 2000, Portland, Oregon 97232
10	Douglas L. Anderson	1111 South 103rd Street, Omaha, Nebraska 68124
11	Patrick J. Goodman	666 Grand Avenue, 29th Floor, Des Moines, Iowa 50309
12	Natalie L. Hocken	825 NE Multnomah, Suite 2000, Portland, Oregon 97232
13	Andrea L. Kelly	1800 M Street NW, Suite 300, Washington, DC 20036
14	Micheal G. Dunn	1407 West North Temple, Suite 320, Salt Lake City, Utah 84116
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Schedule Page: 105 Line No.: 4 Column: a

Stefan A. Bird was elected President and Chief Executive Officer ("CEO") of Pacific Power and director of PacifiCorp effective March 10, 2015. Refer to Item 13 in Important Changes During the Year in this Form No. 1.

Schedule Page: 105 Line No.: 6 Column: a

Cindy A. Crane, President and CEO of Rocky Mountain Power, was elected director of PacifiCorp effective March 10, 2015. Refer to Item 13 in Important Changes During the Year in this Form No. 1.

Schedule Page: 105 Line No.: 8 Column: a

R. Patrick Reiten, the former President and CEO of Pacific Power, was elected President and CEO of PacifiCorp Transmission effective March 10, 2015. Refer to Item 13 in Important Changes During the Year in this Form No. 1.

Schedule Page: 105 Line No.: 13 Column: a

Andrea L. Kelly, Senior Vice President, Legislative and Regulatory Strategy of Berkshire Hathaway Energy Company, was elected director of PacifiCorp effective March 10, 2015. Refer to Item 13 in Important Changes During the Year in this Form No. 1.

Schedule Page: 105 Line No.: 14 Column: a

Micheal G. Dunn, former President and CEO of PacifiCorp Energy, resigned as a director and employee effective March 2015. Refer to Item 13 in Important Changes During the Year in this Form No. 1.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

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

Does the respondent have formula rates? [X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	FERC Electric Tariff Volume No. 11, Attachment H-1	ER11-3643
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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 (2) [ ] A Resubmission	/ /	End of 2015/Q4

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

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[X] Yes
[ ] No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20150306-5249	03/06/2015	ER15-1187		
2	20150417-5193	04/17/2015	ER15-1524		
3	20150515-5231	05/15/2015	ER11-3643		
4	20150717-5126	07/17/2015	ER11-3643		
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Schedule Page: 1061 Line No.: 1 Column: d

PacifiCorp submits tariff filing per 35.13(a)(2)(iii: OATT Revised Attachment H-1 (Rev Depreciation Rates 2015) to be effective 6/1/2015 under ER15-1187

Schedule Page: 1061 Line No.: 1 Column: e

PacifiCorp's Volume No. 11 Open Access Transmission Tariff

Schedule Page: 1061 Line No.: 2 Column: d

PacifiCorp submits tariff filing per 35.13(a)(2)(iii: OATT Formula Rate - Schedule 10 Loss Factor) to be effective 6/1/2015 under ER15-1524 The Commission approved the new Schedule 10 Loss Factor rate with an effective date 12/1/2015

Schedule Page: 1061 Line No.: 2 Column: e

PacifiCorp's Volume No. 11 Open Access Transmission Tariff

Schedule Page: 1061 Line No.: 3 Column: d

Transmission Formula Rate Annual Update Informational Filing of PacifiCorp under ER11-3643

Schedule Page: 1061 Line No.: 3 Column: e

PacifiCorp's Volume No. 11 Open Access Transmission Tariff

Schedule Page: 1061 Line No.: 4 Column: d

Supplement to May 15, 2015 Transmission Formula Rate Annual Update Informational Filing of PacifiCorp under ER11-3643

Schedule Page: 1061 Line No.: 4 Column: e

PacifiCorp's Volume No. 11 Open Access Transmission Tariff

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

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

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

ITEM 1.

The following table includes new or modified franchise agreements. The fee represents the fee attached to the franchise agreement.

State	Effective Date	Expiration Date	Fee
California (1)			
None			
Idaho (2)			
Grace	01/07/2015	01/07/2035	-
Menan	06/30/2015	06/30/2065	-
Ucon	07/20/2015	07/20/2040	3.0%
Parker	09/25/2015	09/25/2065	-
Sugar City	09/25/2015	09/25/2035	3.0%
Roberts	09/25/2015	09/25/2065	-
Oregon (3)			
Klamath Falls	03/16/2015	03/16/2025	7.0%
North Bend	04/08/2015	04/08/2025	9.0%
Gold Hill	05/14/2015	05/14/2025	7.0%
Wasco	06/05/2015	06/05/2020	3.5%
Sublimity	06/11/2015	06/11/2035	3.5%
Coos Bay	07/17/2015	07/17/2025	9.0%
Cannon Beach	07/17/2015	07/17/2020	3.5%
Albany	07/22/2015	07/22/2025	7.0%
Prineville	08/07/2015	06/30/2020	5.0%
Sweet Home	10/13/2015	10/13/2025	5.0%
Lincoln City	11/09/2015	11/09/2025	5.0%
Coquille	11/17/2015	11/17/2025	8.5%
Utah (4)			
Carbon County	01/01/2015	01/01/2035	-
Richfield	02/06/2015	02/06/2025	-
Delta	03/25/2015	03/25/2035	-
Eagle Mountain	03/25/2015	03/25/2020	-
Apple Valley	04/17/2015	04/17/2025	-
Millard County	05/15/2015	05/15/2030	-
Wellsville	05/15/2015	05/15/2035	-
North Ogden	06/03/2015	06/03/2025	-
Ivins	06/30/2015	06/30/2025	-
Pleasant Grove	07/10/2015	07/10/2025	-
Layton	07/20/2015	08/18/2020	-
Corinne	08/07/2015	08/07/2025	-
Vineyard	11/17/2015	11/17/2035	-
Huntington	11/25/2015	11/25/2035	-
Harrisville	11/25/2015	11/25/2025	-
Washington (4)			
None			
Wyoming (5)			
Buffalo	03/25/2015	03/25/2040	4.0%
Douglas	09/08/2015	09/08/2030	4.0%
Green River	11/20/2015	11/20/2025	3.0%

(1) In California, franchise agreement fees are an expense to PacifiCorp and are embedded in rates.

(2) In Idaho, PacifiCorp collects franchise agreement fees from customers and remits them directly to the applicable municipalities.

(3) In Oregon, the first 3.5% of the franchise agreement fee is an expense to PacifiCorp and is embedded in rates. Any amount above the 3.5% is collected from customers and remitted directly to the applicable municipalities.

(4) In Utah and Washington, PacifiCorp collects associated taxes from customers and remits them directly to the applicable municipalities.

(5) In Wyoming, the first 1.0% of the franchise agreement fee 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.

None.

ITEM 3.

In March 2015, PacifiCorp acquired certain distribution and transmission systems and facilities from Eagle Mountain City, a Utah municipal corporation ("the City"), assumed certain liabilities and began providing retail electric service to the City's approximately 6,700 customers. PacifiCorp recorded the transaction in Account 102, Electric plant purchased or sold, in March 2015. The acquisition of the transmission facilities component of this transaction was authorized by the Federal Energy Regulatory Commission ("FERC") in Docket No. EC15-41-000 in January 2015. In September 2015, the FERC in Docket No. AC15-182-000 approved the journal entries required by the Uniform System of Accounts as filed by PacifiCorp in September 2015. Accordingly, PacifiCorp cleared Account 102, Electric purchased or sold and recorded the purchase to the appropriate accounts.

In March 2015, PacifiCorp sold the Fountain Green hydroelectric generating plant in Sanpete County, Utah to the Utah Division of Wildlife Resources in exchange for a transmission line corridor easement in Salt Lake County, Utah and recorded the transaction in Account 102, Electric plant purchased or sold. In July 2015, PacifiCorp filed with the FERC to approve the journal entries required by the Uniform System of Accounts in Docket No. AC15-163-000 and filed with the FERC additional information related to the sale in early April 2016. A notice of the transaction was submitted to the Idaho Public Utilities Commission ("IPUC") and commission authorizations are as follows:

- Wyoming Public Service Commission ("WPSC") – Docket No. 20000-459-EA-14, January 2015.
- Oregon Public Utility Commission ("OPUC") – Docket No. UP 312, Order No. 15-071, March 2015.

In May 2015, the Navajo Nation Council and President of the Navajo Nation approved the agreement with PacifiCorp for the sale of certain facilities located in San Juan County, Utah to the Navajo Tribal Utility Authority ("NTUA"). These facilities, substantially consisting of distribution facilities, provide service to approximately 1,000 customers on the Navajo Nation Reservation. PacifiCorp filed for approval of the sale with the Utah Public Service Commission ("UPSC") and the WPSC in December 2015 and with the OPUC in January 2016. A notice of the transaction was submitted to the IPUC in January 2016. Incorporated as part of the agreement for the sale of facilities is a power supply agreement with the NTUA for PacifiCorp to sell power to the NTUA, which is to become effective after the closing of the sale and commission approval.

In June 2015, PacifiCorp sold certain mining assets located in Utah attributable to the closure of mining operations at the Energy West Mining Company. For further discussion, refer to Note 5 of Notes to Financial Statements in this Form No. 1. Commission authorizations for the sale of certain mining assets are as follows:

- UPSC – Docket No. 14-035-147, April 2015.
- IPUC – Order No. 33304, Case No. PAC-E-14-10, May 2015.
- OPUC – Docket No. UM 1712, Order No. 15-161, May 2015.
- WPSC – Docket No. 20000-464-EA-14, May 2015.

In October 2015, PacifiCorp executed the exchange of certain transmission-related equipment and facilities with Idaho Power Company ("Idaho Power") and terminated and amended certain legacy long-term transmission agreements with Idaho Power. For further discussion of addition of transmission-related equipment and facilities, refer to Item 5 in Important Changes During the Year in this Form No. 1. Commission authorizations are as follows:

- FERC – Docket No. EC15-54-000, ER15-680-000 and ER15-681-000, June 2015.
- IPUC – Order No. 33313, Case No. PAC-E-14-11, June 2015.
- OPUC – Docket No. UP 315, Order No. 15-184, June 2015.
- WPSC – Docket No. 20000-465-EA-14, August 2015.
- California Public Utilities Commission – Decision 15-08-037, Application 14-12-022, August 2015.
- Washington Utilities and Transportation Commission ("WUTC") – Docket No. UE-144136, September 2015.

In December 2015, PacifiCorp sold the assets at Camas Cogeneration facilities located in Camas, Washington and associated systems directly related to its operation to Georgia-Pacific Consumer Products LLC and recorded the sale in Account 102, Electric plant purchased or sold. In February 2016, PacifiCorp filed with the FERC to approve the journal entries required by the Uniform System of Accounts in Docket No. AC16-46-000. Commission authorizations are as follows:

- OPUC – Docket No. UP 325, Order No. 15-151, May 2015.
- WPSC – Docket No. 20000-475-EA-15, September 2015.

ITEM 4.

None.

ITEM 5.

In March 2015, PacifiCorp acquired from Eagle Mountain City, a Utah municipal corporation, certain distribution and transmission systems and facilities, assumed certain liabilities and began providing retail electric service to Eagle Mountain City's approximately 6,500 residential and 200 commercial customers. For the year ended December 31, 2015, PacifiCorp provided service to approximately 7,100 residential and 300 commercial customers in Eagle Mountain City and reported $8.6 million in revenues. Refer to Item 3 in Important Changes During the Year in this Form No. 1 for Commission authorizations.

In April 2015, PacifiCorp and the California Independent System Operator Corporation ("California ISO") entered into a non-binding memorandum of understanding to explore the feasibility, costs and benefits of PacifiCorp joining a regional ISO as a participating transmission owner if the California ISO becomes a regional ISO by modifying its governance structure and expanding its balancing authority area. A comprehensive benefits study was completed and results were publicly announced in October 2015, along with an extension of the non-binding memorandum of understanding. The benefits study demonstrated gross benefits for customers exist, warranting further exploration and analysis of integration. PacifiCorp and the California ISO have initiated a stakeholder input and review process. If PacifiCorp decides to become a participating transmission owner in the regional ISO, it will seek necessary regulatory approvals, including from its state regulatory commissions and the FERC. Joining the regional ISO would extend PacifiCorp's current participation in the real-time market through the Energy Imbalance Market to participation in the day-ahead energy market operated by the California ISO, in addition to unified planning and operation of PacifiCorp's transmission network.

In May 2015, PacifiCorp's Energy Gateway Transmission Expansion Program placed into service a 170-mile single-circuit 345kV transmission line between the Sigurd Substation in central Utah and the Red Butte Substation in southwest Utah. The Energy Gateway Transmission line segments are intended to: (a) address customer load growth; (b) improve system reliability; (c) reduce transmission system constraints; (d) provide access to diverse generation resources, including renewable resources; and (e) improve the flow of electricity throughout PacifiCorp's service territories in Utah, Oregon, Wyoming, Washington, Idaho and California. Proposed transmission line segments are evaluated to ensure optimal benefits and timing before committing to move forward with permitting and construction.

In October 2015, PacifiCorp and Idaho Power each transferred to the other party full or undivided interests in specified transmission-related equipment and facilities under a Joint Purchase and Sale Agreement executed in October 2014. Contemporaneously with the Joint Purchase and Sale Agreement, PacifiCorp and Idaho Power executed a Joint Ownership and Operating Agreement applicable to the specified transmission-related equipment and facilities in the states of Idaho, Oregon, Washington and Wyoming. There were no significant changes to customers and/or revenue associated with this exchange. Refer to Item 3 in Important Changes During the Year in this Form No. 1 for Commission authorizations.

Refer to pages 424-425, Transmission lines added during the year, in this Form No. 1 for additional information regarding transmission lines added or removed during the year ended December 31, 2015.

ITEM 6.

Short-term Debt and Credit Facilities

Regulatory authorities limit PacifiCorp to $1.5 billion of short-term debt. PacifiCorp had $20 million of short-term debt outstanding as of December 31, 2015 at a weighted average interest rate of 0.65%.

Commission authorizations currently 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.
- WUTC – Docket No. UE-980404, dated April 8, 1998.
- IPUC – Case No. PAC-E-16-03, Order No. 33476, dated March 4, 2016, effective through April 30, 2021.
- FERC – Docket No. ES16-3-000, dated December 4, 2015, letter order effective January 1, 2016 through December 31, 2017.

For further discussion, refer to Note 6 of Notes to Financial Statements in this Form No. 1.

Long-term Debt

In June 2015, PacifiCorp issued $250 million of its 3.35% First Mortgage Bonds due July 2025. The net proceeds were used to fund capital expenditures and for general corporate purposes, including retirement of short-term debt.

PacifiCorp currently has regulatory authority from the OPUC and the IPUC to issue an additional $1.325 billion of long-term debt. PacifiCorp must make a notice filing with the WUTC prior to any future issuance. State commission authorizations for the above issuance and future issuances are as follows:

- OPUC – Docket No. UF-4288, Order No. 14-268, dated July 22, 2014.
- IPUC – Case No. PAC-E-14-05, Order No. 33083, dated July 29, 2014.

As of December 31, 2015, PacifiCorp had $310 million of letters of credit providing credit enhancement and liquidity support for variable-rate tax-exempt bond obligations totaling $305 million plus interest. These letters of credit were fully available as of December 31, 2015 and expire periodically through March 2017.

PacifiCorp's Mortgage and Deed of Trust creates a lien on most of PacifiCorp's electric utility property, allowing the issuance of bonds based on a percentage of utility property additions, bond credits arising from retirement of previously outstanding bonds or deposits of cash. The amount of bonds that PacifiCorp may issue generally is also subject to a net earnings test. As of December 31, 2015, PacifiCorp estimated it would be able to issue up to $9.3 billion of new first mortgage bonds under the most restrictive issuance test in the mortgage. Any issuances are subject to market conditions and amounts may be further limited by regulatory authorizations or commitments or by covenants and tests contained in other financing agreements. PacifiCorp also has the ability to release property from the lien of the mortgage on the basis of property additions, bond credits or deposits of cash.

ITEM 7.

None.

ITEM 8.

For the year ended December 31, 2015, PacifiCorp's bargaining unit wage scale changes were as follows:

Unions Represented	% Increase (1)	Effective Date(s)	Estimated Annual Financial Impact (2)
IBEW 57 Power Delivery (UT, ID & WY)	1.82%	01/26/2015	$ 1,423,222
IBEW 57 Power Supply (UT, ID & WY)	1.87%	01/26/2015	707,635
IBEW 57 Combustion Turbine (UT)	1.87%	01/26/2015	59,253
IBEW 659 (OR, CA)	1.29%	04/26/2015	414,954
UWUA 197 (OR)	1.20%	05/26/2015	18,827
IBEW 57 Laramie (WY)	1.03%	06/26/2015	4,985
UWUA 127 (WY)	0.52%	09/26/2015	237,146
IBEW 125 (OR, WA)	0.12%	12/14/2015	29,969
Total			$ 2,895,991

(1) This percentage increase represents the increase in wages from the effective date of the increase to the end of the calendar year as compared to the wage scale of the prior calendar year.

(2) The estimated annual impact is based on the time period from the effective date of the increase to the end of the calendar year. Some amounts may be reimbursed by joint owners.

ITEM 9.

Refer to Note 13 of Notes to Financial Statements in this Form No. 1 for information regarding certain legal proceedings affecting PacifiCorp.

ITEM 10.

In March 2016, Pacific Minerals, Inc., a wholly owned subsidiary of PacifiCorp, declared and paid a dividend of $25 million to PacifiCorp.

Refer to page 429, Transactions with Associated (Affiliated) Companies, in this Form No. 1 for information regarding related-party transactions.

There have been no officer, director or security holder transactions during the year ended December 31, 2015 other than preferred and common stock dividends declared and paid.

ITEM 11.

(Reserved.)

ITEM 12.

Utah Senate Bill 115 ("SB 115"), Sustainable Transportation and Energy Plan, was signed into law in March 2016. The legislation establishes a five year pilot program to provide mandated funding for electric vehicle infrastructure and clean coal research, and authorizes funding at the commission’s discretion for solar development, utility-scale battery storage, and other innovative technology, economic development and air quality initiatives. SB 115 also authorizes the development of a renewable energy tariff for large customer loads. The legislation also allows PacifiCorp to change its accounting for energy efficiency services and programs from expense to capital and to create a regulatory liability that may be used for depreciation of its coal-fired plants. The legislation also mandates full recovery of Utah's share of incremental fuel, purchased power and other variable supply costs through the energy balancing account that are not fully in base rates rather than the prior recovery of 70%.

In March 2016, Oregon Senate Bill 1547-B ("SB 1547-B"), the Clean Electricity and Coal Transition Plan, was signed into law. SB 1547-B requires that coal-fired resources are eliminated from Oregon's allocation of electricity by January 1, 2030, and increases the current Renewable Portfolio Standards ("RPS") target from 25% in 2025 to 50% by 2040. SB 1547-B also implements new renewable energy credit banking provisions, as well as the following interim RPS targets: 27% in 2025 through 2029, 35% in 2030 through 2034, 45% in 2035 through 2039, and 50% by 2040 and subsequent years.

ITEM 13.

In March 2015, PacifiCorp reorganized its divisions to be comprised of Rocky Mountain Power, Pacific Power and PacifiCorp Transmission. Stefan A. Bird was elected President and Chief Executive Officer ("CEO") of Pacific Power effective March 10, 2015. R. Patrick Reiten, former President and CEO of Pacific Power, was elected President and CEO of PacifiCorp Transmission effective March 10, 2015.

Mr. Bird, Cindy A. Crane, President and CEO of Rocky Mountain Power, and Andrea L. Kelly, Senior Vice President, Legislative and Regulatory Strategy of Berkshire Hathaway Energy Company, were elected directors of PacifiCorp effective March 10, 2015.

Micheal G. Dunn, former President and CEO of PacifiCorp Energy resigned as a director and employee effective March 2015.

Douglas K. Stuver resigned as an employee and Senior Vice President and Chief Financial Officer ("CFO") of PacifiCorp effective August 13, 2015. Nikki L. Kobliha was appointed Vice President and CFO of PacifiCorp effective August 13, 2015 and was elected to that position on October 26, 2015.

ITEM 14.

Not applicable.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	26,729,137,536	26,026,444,483
3	Construction Work in Progress (107)	200-201	628,213,113	934,535,929
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		27,357,350,649	26,960,980,412
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	9,237,522,532	9,057,705,065
6	Net Utility Plant (Enter Total of line 4 less 5)		18,119,828,117	17,903,275,347
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)		18,119,828,117	17,903,275,347
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		13,824,869	13,345,624
19	(Less) Accum. Prov. for Depr. and Amort. (122)		3,032,392	2,556,976
20	Investments in Associated Companies (123)		69,928	69,928
21	Investment in Subsidiary Companies (123.1)	224-225	241,143,969	227,471,078
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)		89,802,688	83,174,506
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		15,562,725	19,384,022
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	128,978
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		357,371,787	341,017,160
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		5,873,910	7,178,730
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		33,910	6,297,596
39	Notes Receivable (141)		10,055,988	52,493
40	Customer Accounts Receivable (142)		400,806,409	376,015,082
41	Other Accounts Receivable (143)		42,519,736	38,029,262
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		7,006,495	7,018,317
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		23,759,933	152,259,841
45	Fuel Stock (151)	227	192,305,988	198,515,639
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	233,132,093	223,638,201
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		57,531,155	54,470,840
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		1,485,898	1,902,475
61	Accrued Utility Revenues (173)		244,424,000	243,252,000
62	Miscellaneous Current and Accrued Assets (174)		131,614	180,653
63	Derivative Instrument Assets (175)		8,433,083	18,078,275
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	128,978
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)		1,213,487,222	1,312,723,792
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		33,071,963	34,036,382
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	1,679,069,828	1,589,995,081
73	Prelim. Survey and Investigation Charges (Electric) (183)		973,951	3,103,498
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)		23,727	80,622
78	Miscellaneous Deferred Debits (186)	233	70,244,403	110,913,409
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)		6,351,794	7,184,006
82	Accumulated Deferred Income Taxes (190)	234	606,211,204	544,969,532
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,395,946,870	2,290,282,530
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		22,086,633,996	21,847,298,829

Schedule Page: 110 Line No.: 44 Column: c

As of December 31, 2015, Account 146, Accounts receivable from associated companies, included $20,772,337 of income taxes receivable from Berkshire Hathaway Energy Company, PacifiCorp’s indirect parent company.

Schedule Page: 110 Line No.: 44 Column: d

As of December 31, 2014, Account 146, Accounts receivable from associated companies, included $139,681,803 of income taxes receivable from Berkshire Hathaway Energy Company, PacifiCorp’s indirect parent company.

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	2,397,600	2,397,600
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	1,102,063,956	1,102,063,956
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)	254b	41,101,061	41,101,061
11	Retained Earnings (215, 215.1, 216)	118-119	2,877,592,434	3,145,875,690
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	155,605,539	142,148,647
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)	-12,014,638	-13,665,680
16	Total Proprietary Capital (lines 2 through 15)		7,502,489,726	7,755,665,048
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	7,159,339,000	7,031,538,000
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)		69,100	80,126
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		12,502,206	13,185,043
24	Total Long-Term Debt (lines 18 through 23)		7,146,905,894	7,018,433,083
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		30,062,429	31,882,690
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		26,550,966	15,776,598
29	Accumulated Provision for Pensions and Benefits (228.3)		336,117,800	324,459,642
30	Accumulated Miscellaneous Operating Provisions (228.4)		37,102,444	37,861,624
31	Accumulated Provision for Rate Refunds (229)		58,173	1,879,732
32	Long-Term Portion of Derivative Instrument Liabilities		32,083,864	35,217,373
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		224,250,680	134,721,631
35	Total Other Noncurrent Liabilities (lines 26 through 34)		686,226,356	581,799,290
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		20,000,000	20,000,000
38	Accounts Payable (232)		445,603,914	436,531,636
39	Notes Payable to Associated Companies (233)		15,242,674	0
40	Accounts Payable to Associated Companies (234)		140,098,106	147,513,984
41	Customer Deposits (235)		45,700,120	39,692,452
42	Taxes Accrued (236)	262-263	41,847,694	39,025,536
43	Interest Accrued (237)		119,224,245	113,861,896
44	Dividends Declared (238)		40,475	40,475
45	Matured Long-Term Debt (239)		0	0

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		20,333,462	19,834,847
48	Miscellaneous Current and Accrued Liabilities (242)		69,280,619	69,093,393
49	Obligations Under Capital Leases-Current (243)		2,207,436	1,986,489
50	Derivative Instrument Liabilities (244)		69,761,281	75,193,965
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		32,083,864	35,217,373
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)		957,256,162	927,557,300
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		33,717,019	31,403,438
57	Accumulated Deferred Investment Tax Credits (255)	266-267	22,505,122	27,213,937
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	301,476,278	303,969,379
60	Other Regulatory Liabilities (254)	278	77,876,318	71,012,945
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	285,986,998	252,151,842
63	Accum. Deferred Income Taxes-Other Property (282)		4,414,667,387	4,244,780,923
64	Accum. Deferred Income Taxes-Other (283)		657,526,736	633,311,644
65	Total Deferred Credits (lines 56 through 64)		5,793,755,858	5,563,844,108
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		22,086,633,996	21,847,298,829

Schedule Page: 112 Line No.: 39 Column: c

Represents amounts due to Pacific Minerals, Inc., a wholly owned subsidiary of PacifiCorp, pursuant to an umbrella loan agreement for which interest is determined daily and is equal to the lowest cost of borrowings PacifiCorp could otherwise incur externally. At December 31, 2015 the interest rate on the outstanding borrowings was 0.65%.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STATEMENT OF INCOME

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

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility 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.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	5,235,309,367	5,267,001,125		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,565,045,913	2,632,619,056		
5	Maintenance Expenses (402)	320-323	422,197,831	437,565,258		
6	Depreciation Expense (403)	336-337	697,031,280	663,171,827		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	37,690,560	40,709,374		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	4,989,371	4,834,296		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)			1,760,602		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		437,693	415,224		
13	(Less) Regulatory Credits (407.4)		118,750	1,049,382		
14	Taxes Other Than Income Taxes (408.1)	262-263	185,302,308	171,415,396		
15	Income Taxes - Federal (409.1)	262-263	121,054,868	-2,889,557		
16	- Other (409.1)	262-263	25,050,102	9,721,676		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	1,039,923,787	1,071,119,870		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	861,868,065	760,877,449		
19	Investment Tax Credit Adj. - Net (411.4)	266	-4,756,408	-5,019,198		
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)		320	1,117		
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)		4,231,980,170	4,263,495,876		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		1,003,329,197	1,003,505,249		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
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
5,235,309,367	5,267,001,125					2
						3
2,565,045,913	2,632,619,056					4
422,197,831	437,565,258					5
697,031,280	663,171,827					6
						7
37,690,560	40,709,374					8
4,989,371	4,834,296					9
	1,760,602					10
						11
437,693	415,224					12
118,750	1,049,382					13
185,302,308	171,415,396					14
121,054,868	-2,889,557					15
25,050,102	9,721,676					16
1,039,923,787	1,071,119,870					17
861,868,065	760,877,449					18
-4,756,408	-5,019,198					19
						20
						21
320	1,117					22
						23
						24
4,231,980,170	4,263,495,876					25
1,003,329,197	1,003,505,249					26

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		1,003,329,197	1,003,505,249		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		1,722,065	1,742,323		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		1,740,032	1,612,424		
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)		124,007	46,644		
35	Nonoperating Rental Income (418)		187,080	164,280		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	13,544,949	14,581,067		
37	Interest and Dividend Income (419)		9,749,146	7,738,789		
38	Allowance for Other Funds Used During Construction (419.1)		32,841,065	50,655,904		
39	Miscellaneous Nonoperating Income (421)		478,158	353,146		
40	Gain on Disposition of Property (421.1)		1,427,360	224,256		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		58,085,784	73,800,697		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		555,201	11,056		
44	Miscellaneous Amortization (425)		1,343,975	1,342,957		
45	Donations (426.1)		2,364,473	2,522,386		
46	Life Insurance (426.2)		-4,497,390	-6,393,772		
47	Penalties (426.3)		1,526,588	1,814,037		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		2,593,244	2,583,944		
49	Other Deductions (426.5)		2,407,771	37,428,313		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		6,293,862	39,308,921		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	299,513	203,109		
53	Income Taxes-Federal (409.2)	262-263	4,267,107	-6,629,160		
54	Income Taxes-Other (409.2)	262-263	579,829	-900,793		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	128,771,334	102,052,978		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	131,834,874	105,466,318		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		553,152	691,070		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		1,529,757	-11,431,254		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		50,262,165	45,923,030		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		356,471,778	358,380,033		
63	Amort. of Debt Disc. and Expense (428)		4,088,677	4,073,420		
64	Amortization of Loss on Reaquired Debt (428.1)		832,212	905,935		
65	(Less) Amort. of Premium on Debt-Credit (429)		11,026	11,026		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		19,377	2,512		
68	Other Interest Expense (431)		14,445,893	13,513,332		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		17,591,087	25,295,555		
70	Net Interest Charges (Total of lines 62 thru 69)		358,255,824	351,568,651		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		695,335,538	697,859,628		
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)		695,335,538	697,859,628		

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

Depreciation expense associated with transportation equipment is generally charged to operations and maintenance expense and construction work in progress. During the years ended December 31, 2015 and 2014, depreciation expense associated with transportation equipment was $14,214,593 and $13,767,456, respectively.

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

Generally, 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 generally charged to operations and maintenance expense and construction work in progress. During the years ended December 31, 2015 and 2014, payroll taxes were $39,835,178 and $40,126,082, respectively.

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

Generally, 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 (2) [ ] A Resubmission	/ /	End of 2015/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		3,135,214,887	3,180,100,349
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		681,790,589	683,278,561
17	Appropriations of Retained Earnings (Acct. 436)			
18	Appropriation of excess earnings at certain hydroelectric generating facilities	215.1	-5,674,637	(3,096,169)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-5,674,637	(3,096,169)
23	Dividends Declared-Preferred Stock (Account 437)			
24	Preferred Stock, various series and rates	238	-161,902	(161,902)
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-161,902	(161,902)
30	Dividends Declared-Common Stock (Account 438)			
31	Common Stock	238	-950,000,000	(725,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-950,000,000	(725,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings	216.1	88,057	94,048
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,861,256,994	3,135,214,887
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		16,335,440	10,660,803
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		16,335,440	10,660,803
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		2,877,592,434	3,145,875,690
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		142,148,647	127,661,628
50	Equity in Earnings for Year (Credit) (Account 418.1)		13,544,949	14,581,067
51	(Less) Dividends Received (Debit)			
52	Transfers to/from Unappropriated Retained Earnings (Account 216)		-88,057	(94,048)
53	Balance-End of Year (Total lines 49 thru 52)		155,605,539	142,148,647

Schedule Page: 118 Line No.: 24 Column: c

Outstanding shares of preferred stock as of December 31, 2015 and dividends on preferred stock during the year ended December 31, 2015 were as follows:

	Shares	Dividend
6.00% Serial Preferred	5,930	$ 35,580
7.00% Serial Preferred	18,046	126,322
	23,976	$161,902

Schedule Page: 118 Line No.: 24 Column: d

Outstanding shares of preferred stock as of December 31, 2014 and dividends on preferred stock during the year ended December 31, 2014 were as follows:

	Shares	Dividend
6.00% Serial Preferred	5,930	$ 35,580
7.00% Serial Preferred	18,046	126,322
	23,976	$161,902

Schedule Page: 118 Line No.: 37 Column: c

In September 2015, Trapper Mining Inc., a subsidiary of PacifiCorp, paid a dividend of $88,057 to PacifiCorp.

Schedule Page: 118 Line No.: 37 Column: d

In September 2014, Trapper Mining Inc., a subsidiary of PacifiCorp, paid a dividend of $94,048 to PacifiCorp.

Schedule Page: 118 Line No.: 46 Column: c

The balance in Account 215.1, Appropriated retained earnings - Amortization reserve, Federal, is due to requirements of certain hydroelectric relicensing projects.

Schedule Page: 118 Line No.: 46 Column: d

The balance in Account 215.1, Appropriated retained earnings - Amortization reserve, Federal, is due to requirements of certain hydroelectric relicensing projects.

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	695,335,538	697,859,628
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	712,627,877	678,784,159
5	Amortization:	44,050,122	46,983,824
6			
7			
8	Deferred Income Taxes (Net)	174,992,182	306,829,081
9	Investment Tax Credit Adjustment (Net)	-5,309,560	-5,710,268
10	Net (Increase) Decrease in Receivables	-4,106,411	9,327,709
11	Net (Increase) Decrease in Inventory	-7,282,585	31,370,952
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	20,473,475	10,273,904
14	Net (Increase) Decrease in Other Regulatory Assets	48,439,923	-95,045,998
15	Net Increase (Decrease) in Other Regulatory Liabilities	14,305,404	-10,169,717
16	(Less) Allowance for Other Funds Used During Construction	32,841,065	50,655,904
17	(Less) Undistributed Earnings from Subsidiary Companies	13,456,892	14,487,019
18	Amounts Due To/From Affiliates (Net)	117,602,515	-54,351,514
19	Derivative Collateral (Net)	-46,700,000	-16,500,000
20	Other Operating Activities:	5,756,910	21,671,928
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,723,887,433	1,556,180,765
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-948,488,007	-1,115,501,291
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	-32,841,065	-50,655,904
31	Other (provide details in footnote):	-22,770,214	
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-938,417,156	-1,064,845,387
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	19,089,066	1,069,188
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-216,000	-2,060,000
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other Investing Activities:	-484,494	1,624,874
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-920,028,584	-1,064,211,325
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	249,680,000	424,745,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		19,999,528
67	Other (provide details in footnote):	15,237,000	
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	264,917,000	444,744,528
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-122,199,000	-235,762,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-2,600,477	-12,032,497
77	Repayment of Capital Lease Obligations	-1,382,004	-1,844,876
78	Net Decrease in Short-Term Debt (c)	-972	
79			
80	Dividends on Preferred Stock	-161,902	-161,902
81	Dividends on Common Stock	-950,000,000	-725,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-811,427,355	-530,056,747
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-7,568,506	-38,087,307
87			
88	Cash and Cash Equivalents at Beginning of Period	13,476,326	51,563,633
89			
90	Cash and Cash Equivalents at End of period	5,907,820	13,476,326

Schedule Page: 120 Line No.: 4 Column: b

Includes depreciation expense associated with transportation equipment and capital lease assets of $15,596,597 and $15,612,332 during the years ended December 31, 2015 and 2014, respectively.

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

	Years Ended December 31, 2015	Years Ended December 31, 2014
Amortization of software development & other intangibles	$ 39,034,535	$ 42,052,331
Amortization of electric plant acquisition adjustments	4,989,371	4,834,296
Amortization of a regulatory asset	26,216	97,197
	$ 44,050,122	$ 46,983,824

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

	Years Ended December 31, 2015	Years Ended December 31, 2014
Depreciation and depletion included in cost of fuel	$ 1,876,649	$ 24,247,414
Net loss/(gain) on sale of property	390,138	(310,850)
Write-off of assets under construction	3,748,844	362,850
Change in corporate owned life insurance cash surrender value	(4,474,180)	(6,374,744)
Amortization of debt issuance expenses and bond discount/premium	4,077,651	4,062,394
Other	137,808	(315,136)
	$ 5,756,910	$ 21,671,928

Schedule Page: 120 Line No.: 31 Column: a

Acquisition of Eagle Mountain City distribution and transmission assets and liabilities:

Account 101, Electric plant in service	$(32,055,360)
Account 143, Other accounts receivable	(25,638)
Account 154, Plant materials and operating supplies	(493,848)
Account 242, Miscellaneous current and accrued liabilities	10,678
Account 244, Derivative instrument liabilities	3,785,889
Account 253, Other deferred credits	6,008,065
	$(22,770,214)

Schedule Page: 120 Line No.: 37 Column: b

Represents proceeds from the disposal of fixed assets.

Schedule Page: 120 Line No.: 37 Column: c

Represents proceeds from the disposal of fixed assets.

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

	Years Ended December 31, 2015	Years Ended December 31, 2014
Other investments/special funds	$ 1,377,796	$ 1,174,723
Temporary facilities	56,895	32,429
Restricted cash	3,826,237	417,722
Investment in long-term incentive plan securities	(5,745,422)	-
	$ (484,494)	$ 1,624,874

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

Net proceeds of affiliate borrowing from subsidiary company, Pacific Minerals, Inc.

Schedule Page: 120 Line No.: 76 Column: a

	Years Ended December 31, 2015	Years Ended December 31, 2014
Net repayments of affiliate borrowing from subsidiary company, Pacific Minerals, Inc.	$ -	$ (8,615,195)
Long-term debt issuance and other deferred financing costs	(2,600,477)	(3,417,302)
	$ (2,600,477)	$(12,032,497)

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
NOTES TO FINANCIAL STATEMENTS

(1) Organization and Operations

PacifiCorp is a United States regulated electric utility company serving retail customers, including residential, commercial, industrial, irrigation 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 other utilities, energy marketing companies, financial institutions and other market participants. 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 Berkshire Hathaway Energy Company ("BHE"), a holding company based in Des Moines, Iowa that owns subsidiaries principally engaged in energy businesses. BHE 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 ("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 certain applicable 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 accounting and reporting standards and GAAP.

Investments in Subsidiaries

In accordance with FERC Order No. AC11-132, PacifiCorp accounts for its investment in subsidiaries using the equity method for FERC reporting purposes rather than consolidating the assets, liabilities, revenues and expenses of subsidiaries as required by GAAP. GAAP requires that entities in which a company holds a controlling financial interest be consolidated. Also in accordance with FERC Order No. AC11-132, PacifiCorp does not eliminate intercompany profit on transactions with equity investees as would be required under GAAP. The accounting treatment described above has no effect on net income or the combined retained earnings of PacifiCorp and undistributed earnings of subsidiaries.

Costs of Removal

Estimated removal costs that are recovered through approved depreciation rates, but that do not meet the requirements of a legal asset retirement obligation ("ARO") are reflected in the cost of removal regulatory liability under GAAP and as accumulated depreciation under the FERC accounting and reporting standards.

Income Taxes

Accumulated deferred income taxes are classified as net non-current assets or liabilities on the balance sheet for GAAP. Under the FERC accounting and reporting standards, accumulated deferred income taxes are classified as gross non-current assets and gross non-current liabilities. Additionally, there are certain presentational differences between FERC and GAAP for amounts related to unrecognized tax benefits associated with temporary differences in accordance with FERC Docket No. AI07-2-000, "Accounting and Financial Reporting for Uncertainty in Income Taxes." For GAAP, unrecognized tax benefits associated with temporary differences are reflected as other liabilities while for FERC the income tax impact of uncertain tax positions associated with temporary differences are reflected in accumulated deferred income taxes.

Interest and penalties on income taxes for GAAP are classified as income tax expense. All such amounts are classified as interest income, interest expense and penalties under the FERC accounting and reporting standards.

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 the financial statements in conformity with the FERC and 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 revenue and expenses during the period. These estimates include, but are not limited to, the effects of regulation; certain assumptions made in accounting for pension and other postretirement benefits; AROs; income taxes; unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; and accounting for contingencies. Actual results may differ from the estimates used in preparing the financial statements.

Accounting for the Effects of Certain Types of Regulation

PacifiCorp prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, PacifiCorp defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in rates occur.

PacifiCorp continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future rates 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 that could limit PacifiCorp's ability to recover its costs. PacifiCorp believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels. If it becomes no longer probable that the deferred costs or income will be included in future rates, the related regulatory assets and liabilities will be written off to net income or re-established as accumulated other comprehensive income (loss) ("AOCI").

Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Adjustments to transaction prices or quoted market prices may be required in illiquid or disorderly markets in order to estimate fair value. Different valuation techniques may be appropriate under the circumstances to determine the value that would be received to sell an asset or paid to transfer a liability in an orderly transaction. Market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress. Nonperformance or credit risk is considered in determining fair value. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value. Accordingly, estimates of fair value presented herein are not necessarily indicative of the amounts that could be realized in a current or future market exchange.

Cash Equivalents and Restricted Cash and Investments

Cash equivalents consist of funds invested in money market mutual funds, United States Treasury Bills and 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 on the Comparative Balance Sheet. Total cash and cash equivalents were as follows as of December 31 (in millions):

	2015	2014
Cash (131)	$ 6	$ 7
Temporary cash investments (136)	—	6
Total cash and cash equivalents	$ 6	$ 13

Investments

Available-for-sale securities are carried at fair value with realized gains and losses, as determined on a specific identification basis, recognized in earnings and unrealized gains and losses recognized in AOCI, net of tax. As of December 31, 2015 and 2014, PacifiCorp had no unrealized gains and losses on available-for-sale securities. Trading securities are carried at fair value with realized and unrealized gains and losses recognized in earnings.

Allowance for Doubtful Accounts

Accounts receivable are stated at the outstanding principal amount, net of an estimated allowance for doubtful accounts. The allowance for doubtful accounts is based on PacifiCorp's assessment of the collectibility of amounts owed to PacifiCorp by its customers. This assessment requires judgment regarding the ability of customers to pay 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 on the Comparative Balance Sheet, is summarized as follows for the years ended December 31 (in millions):

	2015	2014
Beginning balance	$ 7	$ 8
Charged to operating costs and expenses, net	10	11
Write-offs, net	(10)	(12)
Ending balance	$ 7	$ 7

Derivatives

PacifiCorp employs a number of different derivative contracts, which may include forwards, options, swaps and other agreements, to manage price risk for electricity, natural gas and other commodities and interest rate risk. Derivative contracts are recorded on the Comparative Balance Sheet as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by FERC and GAAP. Derivative balances reflect offsetting permitted under master netting agreements with counterparties and cash collateral paid or received under such agreements.

Commodity derivatives 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. Normal purchases or normal sales contracts are not marked-to-market and settled amounts are recognized as operating revenues or operation expenses on the Statement of Income.

For PacifiCorp's derivative contracts, the settled amount is generally included in rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in rates are recorded as regulatory assets. For a derivative contract not probable of inclusion in rates, changes in the fair value are recognized in earnings.

Inventories

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

Net Utility Plant

General

Additions to utility plant are recorded at cost. PacifiCorp capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs, which include debt and equity allowance for funds used during construction ("AFUDC"). The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed.

Depreciation and amortization are generally computed on the straight-line method based on composite asset class lives prescribed by PacifiCorp's various regulatory authorities or over the assets' estimated useful lives. Depreciation studies are completed periodically to determine the appropriate composite asset class lives, net salvage and depreciation rates. These studies are reviewed and rates are ultimately approved by the various regulatory authorities. Net salvage includes the estimated future residual values of the assets and any estimated removal costs recovered through approved depreciation rates. Estimated removal costs are recorded as either accumulated provision for depreciation or an ARO liability on the Comparative Balance Sheet, depending on whether the obligation meets the requirements of an ARO. As actual removal costs are incurred, the accumulated provision for depreciation or ARO liability is reduced.

Generally when PacifiCorp retires or sells a component of regulated utility plant, it charges the original cost, net of any proceeds from the disposition, to accumulated provision for depreciation. Any gain or loss on disposals of all other assets is recorded through earnings.

Debt and equity AFUDC, which represent the estimated costs of debt and equity funds necessary to finance the construction of utility plant is capitalized as a component of utility plant, with offsetting credits to the Statement of Income. AFUDC is computed based on guidelines set forth by the FERC. After construction is completed, PacifiCorp is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets.

Asset Retirement Obligations

PacifiCorp recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. PacifiCorp's AROs are primarily associated with its generating facilities. 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 original estimate of undiscounted cash flows (with corresponding adjustments to utility plant) 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 utility plant and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability.

Revenue Recognition

Revenue is recognized as electricity is delivered or services are provided. Revenue recognized includes billed and unbilled amounts. As of December 31, 2015 and 2014, unbilled revenue was $245 million and $243 million, respectively, and is included in accrued utility revenues on the Comparative Balance Sheet. Rates charged are established by regulators or contractual arrangements.

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, energy provided to customers since the date of the last meter reading is 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 include, but are not limited to, seasonal weather patterns, total volumes supplied to the system, line losses, economic impacts and composition of sales among customer classes.

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

Income Taxes

Berkshire Hathaway includes PacifiCorp in its United States federal income tax return. Consistent with established regulatory practice, PacifiCorp's provision for income taxes has been computed on a stand-alone basis.

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using estimated income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities that are associated with components of other comprehensive income ("OCI") are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities that are associated with income tax benefits and expense for certain property-related basis differences and other various differences that PacifiCorp is required to pass on to its customers are charged or credited directly to a regulatory asset or liability. These amounts were recognized as regulatory assets of $437 million and $446 million as of December 31, 2015 and 2014, respectively, and regulatory liabilities of $12 million and $13 million as of December 31, 2015 and 2014, 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. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense or a regulatory asset or liability in the period of enactment. Valuation allowances are established when necessary to reduce deferred income tax assets to the amount that is more likely than not to be realized.

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 income tax laws and regulations, which includes consideration of regulatory implications imposed by PacifiCorp's various regulatory jurisdictions. PacifiCorp's income tax returns are subject to continuous examinations by federal, state and local income 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. PacifiCorp recognizes the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that is more likely than not to be realized upon ultimate settlement. Although the ultimate resolution of PacifiCorp's federal, state and local income tax examinations is uncertain, PacifiCorp believes it has made adequate provisions for these income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations, if any, is not expected to have a material impact on PacifiCorp's financial results.

Segment Information

PacifiCorp currently has one segment, which includes its regulated electric utility operations.

New Accounting Pronouncements

In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-02, which creates FASB Accounting Standards Codification ("ASC") Subtopic 842, "Leases" and supersedes Subtopic 840 "Leases." This guidance increases transparency and comparability among entities by recording lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. A lessee should recognize in the statement of financial position a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term. The recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee have not significantly changed from previous guidance. This guidance is effective for interim and annual reporting periods beginning after December 15, 2018, with early adoption permitted, and is required to be adopted using a modified retrospective approach. PacifiCorp is currently evaluating the impact of adopting this guidance on its financial statements and disclosures included within Notes to Financial Statements.

In January 2016, the FASB issued ASU No. 2016-01, which amends FASB ASC Subtopic 825-10, "Financial Instruments - Overall." The amendments in this guidance address certain aspects of recognition, measurement, presentation and disclosure of financial instruments including a requirement that all investments in equity securities that do not qualify for equity method accounting or result in consolidation of the investee be measured at fair value with changes in fair value recognized in net income. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption not permitted, and is required to be adopted prospectively by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. PacifiCorp is currently evaluating the impact of adopting this guidance on its financial statements and disclosures included within Notes to Financial Statements.

In May 2014, the FASB issued ASU No. 2014-09, which creates FASB ASC Topic 606, "Revenue from Contracts with Customers" and supersedes ASC Topic 605, "Revenue Recognition." The guidance replaces industry-specific guidance and establishes a single five-step model to identify and recognize revenue. The core principle of the guidance is that an entity should recognize revenue upon transfer of control of promised goods or services to customers in an amount that reflects the consideration to which an entity expects to be entitled in exchange for those goods or services. Additionally, the guidance requires the entity to disclose further quantitative and qualitative information regarding the nature and amount of revenues arising from contracts with customers, as well as other information about the significant judgments and estimates used in recognizing revenues from contracts with customers. In August 2015, the FASB issued ASU No. 2015-14, which defers the effective date of ASU No. 2014-09 one year to interim and annual reporting periods beginning after December 15, 2017. This guidance may be adopted retrospectively or under a modified retrospective method where the cumulative effect is recognized at the date of initial application. PacifiCorp is currently evaluating the impact of adopting this guidance on its financial statements and disclosures included within Notes to Financial Statements.

Subsequent Events

PacifiCorp has evaluated the impact of events occurring after December 31, 2015 up to February 26, 2016, the date that PacifiCorp's GAAP financial statements were filed with the United States Securities and Exchange Commission and has updated such evaluation for disclosure purposes through April 12, 2016. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

(3) Net Utility Plant

The average depreciation and amortization rate applied to depreciable utility plant was 2.9% and 3.0% for the years ended December 31, 2015 and 2014, respectively.

(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, transmission and distribution facilities. PacifiCorp accounts for its proportionate share of each facility, and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating costs and expenses on 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, 2015 (dollars in millions):

	PacifiCorp Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Jim Bridger Nos. 1 - 4	67%	$ 1,289	$ 565	$ 83
Hunter No. 1	94	469	151	—
Hunter No. 2	60	293	93	—
Wyodak	80	457	193	3
Colstrip Nos. 3 and 4	10	239	130	2
Hermiston	50	177	71	1
Craig Nos. 1 and 2	19	325	216	18
Hayden No. 1	25	76	31	—
Hayden No. 2	13	30	18	7
Foote Creek	79	39	24	—
Transmission and distribution facilities	Various	577	191	46
Total		$ 3,971	$ 1,683	$ 160

In October 2015, PacifiCorp and Idaho Power Company ("Idaho Power") each transferred to the other party full or undivided interests in specified transmission-related equipment and facilities under a Joint Purchase and Sale Agreement executed in October 2014. Contemporaneously with the Joint Purchase and Sale Agreement, PacifiCorp and Idaho Power executed a Joint Ownership and Operating Agreement applicable to the specified transmission-related equipment and facilities.

(5) Regulatory Matters

Regulatory Assets

PacifiCorp had regulatory assets not earning a return on investment of 1.096 billion and $1.479 billion as of December 31, 2015 and 2014, respectively.

Utah Mine Disposition

Due to quality issues with the coal reserves at PacifiCorp's Deer Creek mine in Utah and rising costs at PacifiCorp's wholly owned subsidiary, Energy West Mining Company, PacifiCorp believes the Deer Creek coal reserves are no longer able to be economically mined. As a result, in December 2014, PacifiCorp filed applications with the Utah Public Service Commission ("UPSC"), the Oregon Public Utility Commission ("OPUC"), the Wyoming Public Service Commission ("WPSC") and the Idaho Public Utilities Commission ("IPUC") seeking certain approvals, prudence determinations and accounting orders to close its Deer Creek mining operations, sell certain Utah mining assets, enter into a replacement coal supply agreement, amend an existing coal supply agreement, withdraw from the United Mine Workers of America ("UMWA") 1974 Pension Plan and settle PacifiCorp's other postretirement benefit obligation for UMWA participants (collectively, the "Utah Mine Disposition").

In April 2015, PacifiCorp filed all-party settlement stipulations with the UPSC and the WPSC finding that the decision to enter into the Utah Mine Disposition transaction was prudent and in the public interest. The UPSC approved the stipulation in April 2015 and the WPSC approved the stipulation in May 2015. In May 2015, the OPUC issued its final order concluding that the Utah Mine Disposition transaction produces net benefits for customers and was in the public interest. The IPUC also issued an order in May 2015, approving the Utah Mine Disposition and ruling that the decision to enter into the transaction was prudent and in the public interest. Accordingly, in June 2015, PacifiCorp sold the specified Utah mining assets and the replacement and amended coal supply agreements became effective. Refer to Note 9 for discussion of the UMWA 1974 Pension Plan withdrawal and the settlement of the other postretirement benefit obligation for UMWA participants. The Deer Creek mine is currently idled and closure activities have begun.

In December 2014, PacifiCorp also filed an advice letter with the California Public Utilities Commission ("CPUC"). In July 2015, the CPUC Energy Division issued a letter requiring PacifiCorp to file a formal application for approval of the sale of certain Utah mining assets. Accordingly, in September 2015, PacifiCorp filed an application with the CPUC.

(6) Short-term Debt and Other Financing Agreements

The following table summarizes PacifiCorp's availability under its credit facilities as of December 31 (in millions):

2015:		
Credit facilities	$	1,200
Less:		
Short-term debt		(20)
Tax-exempt bond support and letters of credit		(160)
Net credit facilities	$	1,020
2014:		
Credit facilities	$	1,200
Less:		
Short-term debt		(20)
Letters of credit and tax-exempt bond support		(398)
Net credit facilities	$	782

PacifiCorp has a $600 million unsecured credit facility expiring in June 2017 and a $600 million unsecured credit facility expiring in March 2018. These credit facilities, which support PacifiCorp's commercial paper program, certain series of its tax-exempt bond obligations and provide for the issuance of letters of credit, have a variable interest rate based on the London Interbank Offered Rate or a base rate, at PacifiCorp's option, plus a spread that varies based on PacifiCorp's credit ratings for its senior unsecured long-term debt securities. As of December 31, 2015 and 2014, the weighted average interest rate on commercial paper borrowings outstanding was 0.65% and 0.43%, respectively. These credit facilities require that PacifiCorp's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of each quarter. As of December 31, 2015, PacifiCorp was in compliance with the covenants of its credit facilities.

As of December 31, 2015 and 2014, PacifiCorp had $310 million and $451 million, respectively, of fully available letters of credit issued under committed arrangements, of which $10 million and $270 million as of December 31, 2015 and 2014 were issued under the credit facilities. These letters of credit support PacifiCorp's variable-rate tax-exempt bond obligations and expire through March 2017.

As of December 31, 2015, PacifiCorp had approximately $15 million of additional letters of credit issued on its behalf to provide credit support for certain transactions as required by third parties. These letters of credit were all undrawn as of December 31, 2015 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.

(7) Long-term Debt and Capital Lease Obligations

PacifiCorp's long-term debt generally includes provisions that allow PacifiCorp to redeem the first mortgage bonds in whole or in part at any time through the payment of a make-whole premium. Variable-rate tax-exempt bond obligations are generally redeemable at par value.

In June 2015, PacifiCorp issued $250 million of its 3.35% First Mortgage Bonds due July 2025. The net proceeds were used to fund capital expenditures and for general corporate purposes, including retirement of short-term debt.

PacifiCorp currently has regulatory authority from the OPUC and the IPUC to issue an additional $1.325 billion of long-term debt. PacifiCorp must make a notice filing with the Washington Utilities and Transportation Commission prior to any future issuance. PacifiCorp currently has an effective shelf registration statement filed with the United States Securities and Exchange Commission to issue up to $1.325 billion additional first mortgage bonds through January 2019.

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately $25 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2015.

PacifiCorp has entered into long-term agreements that qualify as capital leases and expire at various dates through March 2035 for transportation services, power purchase agreements and real estate. The transportation services agreements included as capital leases are for the right to use pipeline facilities to provide natural gas to two of PacifiCorp's generating facilities. Net capital lease assets of $32 million and $34 million as of December 31, 2015 and 2014, respectively, were included in net utility plant in the Comparative Balance Sheet.

As of December 31, 2015, the annual principal maturities of long-term debt and total capital lease obligations for 2016 and thereafter are as follows (in millions):

	Long-term Debt	Capital Lease Obligations	Total
2016	$ 66	$ 5	$ 71
2017	52	10	62
2018	586	5	591
2019	350	5	355
2020	38	4	42
Thereafter	6,067	27	6,094
Total	7,159	56	7,215
Unamortized discount	(12)	—	(12)
Amounts representing interest	—	(24)	(24)
Total	$ 7,147	$ 32	$ 7,179

(8) Income Taxes

Income tax expense (benefit) consists of the following for the years ended December 31 (in millions):

	2015	2014
Current:		
Federal	$ 125	$ (10)
State	26	9
Total	151	(1)
Deferred:		
Federal	146	264
State	29	43
Total	175	307
Investment tax credits	(5)	(6)
Total income tax expense	$ 321	$ 300

A reconciliation of the federal statutory income tax rate to the effective income tax rate applicable to income before income tax expense is as follows for the years ended December 31:

	2015	2014
Federal statutory income tax rate	35 %	35 %
State income taxes, net of federal income tax benefit	3	3
Federal income tax credits	(6)	(7)
Other	—	(1)
Effective income tax rate	32 %	30 %

Income tax credits relate primarily to production tax credits earned by PacifiCorp's wind-powered generating facilities. Federal renewable electricity production tax credits are earned as energy from qualifying wind-powered generating facilities is produced and sold and are based on a per-kilowatt hour rate pursuant to the applicable federal income tax law. Wind-powered generating facilities are eligible for the credits for 10 years from the date the qualifying generating facilities are placed in-service.

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

	2015	2014
Deferred income tax assets:		
Employee benefits	$ 190	$ 183
Derivative contracts and unamortized contract values	94	79
State carryforwards	69	68
Loss contingencies	56	51
Asset retirement obligations	81	47
Regulatory liabilities	30	29
Other	86	88
	606	545
Deferred income tax liabilities:		
Property, plant and equipment	(4,701)	(4,497)
Regulatory assets	(639)	(611)
Other	(18)	(22)
	(5,358)	(5,130)
Net deferred income tax liability	$ (4,752)	$ (4,585)

The following table provides PacifiCorp's net operating loss and tax credit carryforwards and expiration dates as of December 31, 2015 (in millions):

	State
Net operating loss carryforwards	$ 1,416
Deferred income taxes on net operating loss carryforwards	$ 52
Expiration dates	2016 - 2032
Tax credit carryforwards	$ 16
Expiration dates	2016 - indefinite

The United States Internal Revenue Service has closed its examination of PacifiCorp's income tax returns through December 31, 2009. State agencies have closed their examinations of PacifiCorp's income tax returns through March 31, 2006, except for the December 31, 1995 and 1997 tax years in Utah.

(9) Employee Benefit Plans

PacifiCorp sponsors defined benefit pension and other postretirement benefit plans that cover the majority of its employees, as well as a defined contribution 401(k) employee savings plan ("401(k) Plan"). In addition, PacifiCorp contributes to a joint trustee pension plan and a subsidiary previously contributed to a multiemployer pension plan for benefits offered to certain bargaining units.

Pension and Other Postretirement Benefit Plans

PacifiCorp's pension plans include a non-contributory defined benefit pension plan, the PacifiCorp Retirement Plan ("Retirement Plan"), and the Supplemental Executive Retirement Plan ("SERP"). The Retirement Plan is closed to all non-union employees hired after January 1, 2008. The SERP was closed to new participants as of March 21, 2006 and froze future accruals for active participants as of December 31, 2014. All non-union Retirement Plan participants hired prior to January 1, 2008 that did not elect to receive equivalent fixed contributions to the 401(k) Plan effective January 1, 2009 continue to earn benefits based on a cash balance formula. In general for union employees, benefits under the Retirement Plan were frozen at various dates from December 31, 2007 through December 31, 2011 as they are now being provided with enhanced 401(k) Plan benefits. However, certain limited union Retirement Plan participants continue to earn benefits under the Retirement Plan based on the employee's years of service and a final average pay formula.

PacifiCorp's other postretirement benefit plan provides healthcare and life insurance benefits to eligible retirees.

Utah Mine Disposition and Labor Agreement

In conjunction with the Utah Mine Disposition described in Note 5, in December 2014, PacifiCorp's subsidiary, Energy West Mining Company, reached a labor settlement with the UMWA covering union employees at PacifiCorp's Deer Creek mining operations. As a result of the labor settlement, the UMWA agreed to assume PacifiCorp's other postretirement benefit obligation associated with UMWA plan participants in exchange for PacifiCorp transferring $150 million to a fund managed by the UMWA. Transfer of the assets and settlement of this obligation occurred in May 2015 and resulted in a remeasurement of the other postretirement plan assets and benefit obligation. As a result of the remeasurement, PacifiCorp recognized a $9 million settlement loss, with the portion that is probable of recovery deferred as a regulatory asset. No curtailment accounting was triggered as a result of the settlement due to an insignificant impact to the average remaining service lives in the plan.

As a result of the closure of the Deer Creek mining operations, withdrawal by Energy West Mining Company from the UMWA 1974 Pension Plan was involuntarily triggered in June 2015 when UMWA employees ceased performing work for the subsidiary. Refer to "Multiemployer and Joint Trustee Pension Plans" below for further information regarding the withdrawal.

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.

Net periodic benefit cost for the plans included the following components for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2015	**2014**	**2015**	**2014**
Service cost	$ 4	$ 5	$ 3	$ 6
Interest cost	53	57	16	28
Expected return on plan assets	(77)	(76)	(23)	(31)
Net amortization	42	29	(4)	2
Net period benefit cost	$ 22	$ 15	$ (8)	$ 5

Funded Status

The following table is a reconciliation of the fair value of plan assets for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2015	**2014**	**2015**	**2014**
Plan assets at fair value, beginning of year	$ 1,146	$ 1,171	$ 482	$ 486
Employer contributions	4	10	1	1
Participant contributions	—	—	6	7
Actual return on plan assets	—	53	1	25
Settlement	—	—	(150)	—
Benefits paid	(107)	(88)	(35)	(37)
Plan assets at fair value, end of year	$ 1,043	$ 1,146	$ 305	$ 482

The following table is a reconciliation of the benefit obligations for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2015	2014	2015	2014
Benefit obligation, beginning of year	$ 1,378	$ 1,230	$ 539	$ 598
Service cost	4	5	3	6
Interest cost	53	57	16	28
Participant contributions	—	—	6	7
Actuarial (gain) loss	(39)	174	(17)	(63)
Settlement	—	—	(150)	—
Benefits paid	(107)	(88)	(35)	(37)
Benefit obligation, end of year	$ 1,289	$ 1,378	$ 362	$ 539
Accumulated benefit obligation, end of year	$ 1,289	$ 1,378		

The actuarial gain associated with the other postretirement benefit obligation during the year ended December 31, 2014 includes a gain that reduced the benefit obligation associated with the UMWA plan participants to $150 million. Refer to "Utah Mine Disposition and Labor Agreement" above.

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

	Pension		Other Postretirement	
	2015	2014	2015	2014
Plan assets at fair value, end of year	$ 1,043	$ 1,146	$ 305	$ 482
Less - Benefit obligation, end of year	1,289	1,378	362	539
Funded status	$ (246)	$ (232)	$ (57)	$ (57)
Amounts recognized on the Comparative Balance Sheet:				
Miscellaneous current and accrued liabilities	$ (4)	$ (4)	$ —	$ —
Accumulated provision for pension and benefits	(242)	(228)	(57)	(57)
Amounts recognized	$ (246)	$ (232)	$ (57)	$ (57)

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 $52 million and $51 million as of December 31, 2015 and 2014, respectively. These assets are not included in the plan assets in the above table, but are reflected in other investments on the Comparative Balance Sheet.

Unrecognized Amounts

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

	Pension		Other Postretirement	
	2015	**2014**	**2015**	**2014**
Net loss	$ 508	$ 520	$ 36	$ 41
Prior service credit	(13)	(21)	(19)	(26)
Regulatory deferrals	(3)	(3)	9	2
Total	$ 492	$ 496	$ 26	$ 17

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2015 and 2014 is as follows (in millions):

	Regulatory Asset	**Accumulated Other Comprehensive Loss**	**Total**
Pension			
Balance, December 31, 2013	$ 313	$ 15	$ 328
Net loss arising during the year	189	8	197
Net amortization	(28)	(1)	(29)
Total	161	7	168
Balance, December 31, 2014	474	22	496
Net loss (gain) arising during the year	40	(2)	38
Net amortization	(41)	(1)	(42)
Total	(1)	(3)	(4)
Balance, December 31, 2015	$ 473	$ 19	$ 492

	Regulatory Asset
Other Postretirement	
Balance, December 31, 2013	$ 77
Net gain arising during the year	(58)
Net amortization	(2)
Total	(60)
Balance, December 31, 2014	17
Net loss arising during the year	5
Net amortization	4
Total	9
Balance, December 31, 2015	$ 26

The net loss, prior service credit and regulatory deferrals that will be amortized in 2016 into net periodic benefit cost are estimated to be as follows (in millions):

	Net Loss	Prior Service Credit	Regulatory Deferrals	Total
Pension	$ 42	$ (8)	$ (1)	$ 33
Other postretirement	1	(7)	1	(5)
Total	$ 43	$ (15)	$ —	$ 28

Plan Assumptions

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

	Pension		Other Postretirement	
	2015	2014	2015	2014
Benefit obligations as of December 31:				
Discount rate	4.40%	4.00%	4.35%	3.90%
Rate of compensation increase	2.75	2.75	N/A	N/A
Net periodic benefit cost for the years ended December 31:				
Discount rate	4.00%	4.80%	3.99%	4.90%
Expected return on plan assets	7.50	7.50	7.08	7.50
Rate of compensation increase	2.75	3.00	N/A	N/A

In establishing its assumption as to the expected return on plan assets, PacifiCorp utilizes the asset allocation and return assumptions for each asset class based on historical performance and forward-looking views of the financial markets. As discussed above in "Utah Mine Disposition and Labor Agreement," PacifiCorp remeasured the other postretirement plan assets and benefit obligation as of May 31, 2015. The other postretirement assumptions for the year ended December 31, 2015 presented above reflect a weighted average calculation that considered the assumptions used in the periods preceding and subsequent to the remeasurement.

As a result of the labor settlement discussed above in "Utah Mine Disposition and Labor Agreement," the benefit obligation for the other postretirement plan is no longer affected by healthcare cost trends. The assumed healthcare cost trend rates used to determine the benefit obligation as of December 31, 2014 were as follows:

Healthcare cost trend rate assumed for next year	8.00 %
Rate that the cost trend rate gradually declines to	5.00 %
Year that the rate reaches the rate it is assumed to remain at	2025

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $4 million and $- million, respectively, during 2016. Funding to PacifiCorp's Retirement Plan trust is based upon the actuarially determined costs of the plan and the requirements of the Internal Revenue Code, the Employee Retirement Income Security Act of 1974 ("ERISA") and the Pension Protection Act of 2006, as amended ("PPA"). PacifiCorp considers contributing additional amounts from time to time in order to achieve certain funding levels specified under the PPA. PacifiCorp's funding policy for its other postretirement benefit plan is to generally contribute an amount equal to the net periodic benefit cost, subject to tax deductibility limitations and other considerations.

The expected benefit payments to participants in PacifiCorp's pension and other postretirement benefit plans for 2016 through 2020 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	**Other Postretirement**
2016	$ 108	$ 28
2017	110	28
2018	108	28
2019	109	27
2020	107	30
2021-2025	448	122

Plan Assets

Investment Policy and Asset Allocations

PacifiCorp's investment policy for its pension and other postretirement benefit plans is to balance risk and return through a diversified portfolio of debt securities, equity securities and other alternative investments. Maturities for debt securities are managed to targets consistent with prudent risk tolerances. The plans retain outside investment advisors to manage plan investments within the parameters outlined by the PacifiCorp Pension Committee. The investment portfolio is managed in line with the investment policy with sufficient liquidity to meet near-term benefit payments.

The target allocations (percentage of plan assets) for PacifiCorp's pension and other postretirement benefit plan assets are as follows as of December 31, 2015:

	Pension(1)	**Other Postretirement**(1)
	%	%
Debt securities(2)	33 - 37	33 - 37
Equity securities(2)	53 - 57	61 - 65
Limited partnership interests	8 - 12	1 - 3
Other	0 - 1	0 - 1

(1) PacifiCorp's Retirement 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 the other postretirement benefit plan are held in Voluntary Employees' Beneficiary Association ("VEBA") trusts, each of which has its own investment allocation strategies. Target allocations for the other postretirement benefit plan include the separate account of the Retirement Plan trust and the VEBA trusts.

(2) For purposes of target allocation percentages and consistent with the plans' investment policy, investment funds are allocated based on the underlying investments in debt and equity securities.

Fair Value Measurements

The following table presents the fair value of plan assets, by major category, for PacifiCorp's defined benefit pension plan (in millions):

	Input Levels for Fair Value Measurements			
	Level 1(1)	**Level 2**(1)	**Level 3**(1)	**Total**
As of December 31, 2015				
Cash equivalents	$ —	$ 10	$ —	$ 10
Debt securities:				
United States government obligations	19	—	—	19
Corporate obligations	—	42	—	42
Municipal obligations	—	5	—	5
Agency, asset and mortgage-backed obligations	—	43	—	43
Equity securities:				
United States companies	408	—	—	408
International companies	17	—	—	17
Investment funds(2)	83	351	—	434
Limited partnership interests(3)	—	—	65	65
Total	$ 527	$ 451	$ 65	$ 1,043
As of December 31, 2014				
Cash equivalents	$ —	$ 8	$ —	$ 8
Debt securities:				
United States government obligations	15	—	—	15
Corporate obligations	—	53	—	53
Municipal obligations	—	8	—	8
Agency, asset and mortgage-backed obligations	—	48	—	48
Equity securities:				
United States companies	488	—	—	488
International companies	16	—	—	16
Investment funds(2)	217	223	—	440
Limited partnership interests(3)	—	—	70	70
Total	$ 736	$ 340	$ 70	$ 1,146

(1) Refer to Note 12 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are substantially comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 53% and 47%, respectively, for 2015 and 50% and 50%, respectively, for 2014, and are invested in United States and international securities of approximately 40% and 60%, respectively, for 2015 and 43% and 57%, respectively, for 2014.

(3) Limited partnership interests include several funds that invest primarily in real estate, buyout, growth equity and venture capital.

The following table presents the fair value of plan assets, by major category, for PacifiCorp's defined benefit other postretirement plan (in millions):

	Input Levels for Fair Value Measurements			
	Level 1(1)	**Level 2(1)**	**Level 3(1)**	**Total**
As of December 31, 2015				
Cash and cash equivalents	$ 4	$ 1	$ —	$ 5
Debt securities:				
United States government obligations	9	—	—	9
Corporate obligations	—	15	—	15
Municipal obligations	—	1	—	1
Agency, asset and mortgage-backed obligations	—	14	—	14
Equity securities:				
United States companies	95	—	—	95
International companies	4	—	—	4
Investment funds(2)	32	126	—	158
Limited partnership interests(3)	—	—	4	4
Total	$ 144	$ 157	$ 4	$ 305
As of December 31, 2014				
Cash and cash equivalents(4)	$ 139	$ —	$ —	$ 139
Debt securities:				
United States government obligations	8	—	—	8
Corporate obligations	—	18	—	18
Municipal obligations	—	2	—	2
Agency, asset and mortgage-backed obligations	—	16	—	16
Equity securities:				
United States companies	112	—	—	112
International companies	4	—	—	4
Investment funds(2)	84	94	—	178
Limited partnership interests(3)	—	—	5	5
Total	$ 347	$ 130	$ 5	$ 482

(1) Refer to Note 12 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are substantially comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 61% and 39%, respectively, for 2015 and 63% and 37%, respectively, for 2014, and are invested in United States and international securities of approximately 67% and 33%, respectively, for 2015 and 64% and 36%, respectively, for 2014.

(3) Limited partnership interests include several funds that invest primarily in real estate, buyout, growth equity and venture capital.

(4) In December 2014, PacifiCorp began to migrate funds to cash and cash equivalents in anticipation of the $150 million to be transferred to a fund managed by the UMWA in May 2015 as a result of the other postretirement settlement. Remaining investments were rebalanced to align to target investment allocations.

For level 1 investments, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. For level 2 investments, the fair value is determined using pricing models or unquoted net asset values based on observable market inputs. For level 3 investments, the fair value is determined using unobservable inputs, such as estimated future cash flows, purchase multiples paid in other comparable third-party transactions or other information. Most investments in limited partnership interests are valued at estimated fair value based on the pension and other postretirement benefit plans' proportionate shares of the partnerships' fair value as recorded in the partnerships' most recently available financial statements adjusted for recent activity and estimated returns. The fair values recorded in the partnerships' financial statements are generally determined based on closing public market prices for publicly traded securities and as determined by the general partners for other investments based on factors including estimated future cash flows, purchase multiples paid in other comparable third-party transactions, comparable public company trading multiples and other information. One of the limited partnerships is valued at the unit price calculated by the general partner primarily based on independent appraised values of the underlying property holdings.

The following table reconciles the beginning and ending balances of PacifiCorp's plan assets measured at fair value using significant Level 3 inputs for the years ended December 31 (in millions):

	Limited Partnership Interests	
	Pension	**Other Postretirement**
Balance, December 31, 2013	$ 86	$ 6
Actual return on plan assets still held at December 31, 2014	(1)	—
Purchases, sales, distributions and settlements	(15)	(1)
Balance, December 31, 2014	70	5
Actual return on plan assets still held at December 31, 2015	5	—
Purchases, sales, distributions and settlements	(10)	(1)
Balance, December 31, 2015	$ 65	$ 4

Multiemployer and Joint Trustee Pension Plans

PacifiCorp contributes to the PacifiCorp/IBEW Local 57 Retirement Trust Fund ("Local 57 Trust Fund") (plan number 001) and its subsidiary, Energy West Mining Company, previously contributed to the UMWA 1974 Pension Plan (plan number 002). Contributions to these pension plans are based on the terms of collective bargaining agreements.

As a result of the Utah Mine Disposition and UMWA labor settlement, PacifiCorp's subsidiary, Energy West Mining Company, triggered involuntary withdrawal from the UMWA 1974 Pension Plan in June 2015 when the UMWA employees ceased performing work for the subsidiary. The estimated withdrawal obligation was recorded in December 2014 when withdrawal was considered probable, and a regulatory asset was established for the portion of the obligation considered probable of recovery. The estimate of the withdrawal obligation provided by the UMWA 1974 Pension Plan is $97 million for a withdrawal occurring by July 1, 2015. Energy West Mining Company may elect to make a lump sum payment or annual installment payments to settle the withdrawal obligation.

The Local 57 Trust Fund is a joint trustee plan such that the board of trustees is represented by an equal number of trustees from PacifiCorp and the union. The Local 57 Trust Fund was established pursuant to the provisions of the Taft-Hartley Act and although formed with the ability for other employers to participate in the plan, there are no other employers that participate in this plan.

The risk of participating in multiemployer pension plans generally differs from single-employer plans in that assets are pooled such that contributions by one employer may be used to provide benefits to employees of other participating employers and plan assets cannot revert back to employers. If an employer ceases participation in the plan, the employer may be obligated to pay a withdrawal liability based on the participants' unfunded, vested benefits in the plan. This occurred as a result of Energy West Mining Company's withdrawal from the UMWA 1974 Pension Plan. If participating employers withdraw from a multiemployer plan, the unfunded obligations of the plan may be borne by the remaining participating employers, including any employers that withdrew during the three years prior to a mass withdrawal.

The following table presents PacifiCorp's and Energy West Mining Company's participation in individually significant joint trustee and multiemployer pension plans for the years ended December 31 (dollars in millions):

Plan name	Employer Identification Number	PPA zone status or plan funded status percentage for plan years beginning July 1, 2015	2014	Funding improvement plan	Surcharge imposed under PPA	Contributions[1] 2015	2014	Year contributions to plan exceeded more than 5% of total contributions[2]
UMWA Pension Plan	52-1050282	Critical and Declining	Critical	Implemented	Yes	$ 1	$ 2	None
Local 57 Trust Fund	87-0640888	At least 80%	At least 80%	None	None	$ 8	$ 9	2014, 2013

(1) PacifiCorp's and Energy West Mining Company's minimum contributions to the plans are based on the amount of wages paid to employees covered by the Local 57 Trust Fund collective bargaining agreements and the number of mining hours worked for the UMWA 1974 Pension Plan, respectively, subject to ERISA minimum funding requirements. As a result of the plan's critical status, Energy West Mining Company was required to begin paying a surcharge for hours worked on and after December 1, 2014.

(2) For the UMWA 1974 Pension Plan, information is for plan year beginning July 1, 2013. Information for the plan years beginning July 1, 2015 and 2014 is not yet available. For the Local 57 Trust Fund, information is for plan years beginning July 1, 2014 and 2013. Information for the plan year beginning July 1, 2015 is not yet available.

The current collective bargaining agreements governing the Local 57 Trust Fund expire in January 2020.

Defined Contribution Plan

PacifiCorp's 401(k) Plan covers substantially all employees. PacifiCorp's matching contributions are based on each participant's level of contribution, and certain participants receive contributions based on eligible pre-tax annual compensation. Contributions cannot exceed the maximum allowable for tax purposes. PacifiCorp's contributions to the 401(k) Plan were $35 million and $34 million for the years ended December 31, 2015 and 2014, respectively.

(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 changes in laws and regulations, 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 on the financial statements other than those included in the accumulated provision for depreciation established via approved depreciation rates in accordance with accepted regulatory practices. These accruals totaled $894 million and $873 million as of December 31, 2015 and 2014, respectively.

The following table reconciles the beginning and ending balances of PacifiCorp's ARO liabilities for the years ended December 31 (in millions):

	2015	2014
Beginning balance	$ 135	$ 138
Change in estimated costs	62	(3)
Additions	30	—
Retirements	(10)	(6)
Accretion	7	6
Ending balance	$ 224	$ 135

Certain of PacifiCorp's decommissioning and reclamation obligations relate to jointly owned facilities and mine sites. PacifiCorp is committed to pay a proportionate share of the decommissioning or reclamation costs. In the event of a default by any of the other joint participants, PacifiCorp 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.

In December 2014, the United States Environmental Protection Agency released its final rule regulating the management and disposal of coal combustion byproducts resulting from the operation of coal-fueled generating facilities, including requirements for the operation and closure of surface impoundment and ash landfill facilities. The final rule was published in the Federal Register in April 2015 and was effective in October 2015. The final rule substantially impacted existing AROs reflected in the December 31, 2015 change in estimated costs above and also resulted in the recognition of additional AROs.

(11) Risk Management and Hedging Activities

PacifiCorp is exposed to the impact of market fluctuations in commodity prices and interest rates. PacifiCorp is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk as it has an obligation to serve retail customer load in its service territories. PacifiCorp's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity and wholesale electricity that is purchased and sold. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. Interest rate risk exists on variable-rate debt and future debt issuances. PacifiCorp does not engage in a material amount of proprietary trading activities.

PacifiCorp has established a risk management process that is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in its business. To mitigate a portion of its commodity price risk, PacifiCorp uses commodity derivative contracts, which may include forwards, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. PacifiCorp manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. Additionally, PacifiCorp may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate PacifiCorp's exposure to interest rate risk. No interest rate derivatives were in place during the periods presented. PacifiCorp does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices.

There have been no significant changes in PacifiCorp's accounting policies related to derivatives. Refer to Notes 2 and 12 for additional information on derivative contracts.

The following table, which reflects master netting arrangements and excludes contracts that have been designated as normal under the normal purchases or normal sales exception afforded by FERC and GAAP, summarizes the fair value of PacifiCorp's derivative contracts, on a gross basis, and reconciles those amounts to the amounts presented on a net basis on the Comparative Balance Sheet (in millions):

	Current Assets	Long-term Assets	Current Liabilities	Long-term Liabilities	Total
As of December 31, 2015					
Not designated as hedging contracts(1):					
Commodity assets	$ 10	$ —	$ 2	$ —	$ 12
Commodity liabilities	(1)	—	(58)	(89)	(148)
Total	9	—	(56)	(89)	(136)
Total derivatives	9	—	(56)	(89)	(136)
Cash collateral receivable	—	—	18	57	75
Total derivatives - net basis	$ 9	$ —	$ (38)	$ (32)	$ (61)
As of December 31, 2014					
Not designated as hedging contracts(1):					
Commodity assets	$ 28	$ —	$ 1	$ —	$ 29
Commodity liabilities	(10)	—	(55)	(49)	(114)
Total	18	—	(54)	(49)	(85)
Total derivatives	18	—	(54)	(49)	(85)
Cash collateral receivable	—	—	14	14	28
Total derivatives - net basis	$ 18	$ —	$ (40)	$ (35)	$ (57)

(1) PacifiCorp's commodity derivatives are generally included in rates and as of December 31, 2015 and 2014, a regulatory asset of $133 million and $85 million, respectively, was recorded related to the net derivative liability of $136 million and $85 million, respectively.

The following table reconciles the beginning and ending balances of PacifiCorp's regulatory assets and summarizes the pre-tax gains and losses on commodity derivative contracts recognized in regulatory assets, as well as amounts reclassified to earnings for the years ended December 31 (in millions):

	2015	2014
Beginning balance	$ 85	$ 55
Changes in fair value recognized in regulatory assets	82	45
Net gains (losses) reclassified to operating revenue	40	(4)
Net losses reclassified to energy costs	(74)	(11)
Ending balance	$ 133	$ 85

Derivative Contract Volumes

The following table summarizes the net notional amounts of outstanding commodity derivative contracts with fixed price terms that comprise the mark-to-market values as of December 31 (in millions):

	Unit of Measure	2015	2014
Electricity purchases (sales)	Megawatt hours	1	(1)
Natural gas purchases	Decatherms	111	113
Fuel oil purchases	Gallons	11	3

Credit Risk

PacifiCorp is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent PacifiCorp's counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, PacifiCorp analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, PacifiCorp enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtains third-party guarantees, letters of credit and cash deposits. If required, PacifiCorp exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

Collateral and Contingent Features

In accordance with industry practice, certain wholesale derivative contracts contain credit support provisions that in part base certain collateral requirements on credit ratings for senior unsecured debt as reported by one or more of the three recognized credit rating agencies. These derivative contracts may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance" in the event of a material adverse change in PacifiCorp's creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2015, PacifiCorp's credit ratings from the three recognized credit rating agencies were investment grade.

The aggregate fair value of PacifiCorp's derivative contracts in liability positions with specific credit-risk-related contingent features totaled $142 million and $113 million as of December 31, 2015 and 2014, respectively, for which PacifiCorp had posted collateral of $75 million and $28 million, respectively, in the form of cash deposits. If all credit-risk-related contingent features for derivative contracts in liability positions had been triggered as of December 31, 2015 and 2014, PacifiCorp would have been required to post $64 million and $75 million, respectively, of additional collateral.

In addition to derivative contracts in liability positions, PacifiCorp has non-derivative wholesale agreements with specified credit-risk-related contingent features that base certain collateral requirements on credit ratings. If all credit-risk-related contingent features or adequate assurance provisions for wholesale agreements, including non-derivative agreements and derivative contracts in liability positions, had been triggered as of December 31, 2015 and December 31, 2014, PacifiCorp would have been required to post $261 million and $233 million, respectively, of additional collateral.

PacifiCorp's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation or other factors.

(12) Fair Value Measurements

The carrying value of PacifiCorp's cash, certain cash equivalents, receivables, other special funds, other investments, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. PacifiCorp has various financial assets and liabilities that are measured at fair value on the financial statements 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 or 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 its own data.

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

	Input Levels for Fair Value Measurements				
	Level 1	**Level 2**	**Level 3**	**Other[1]**	**Total**
As of December 31, 2015					
Assets:					
Commodity derivatives	$ —	$ 9	$ 3	$ (3)	$ 9
Money market mutual funds[2]	13	—	—	—	13
Investment funds	15	—	—	—	15
	$ 28	$ 9	$ 3	$ (3)	$ 37
Liabilities - Commodity derivatives	$ —	$ (148)	$ —	$ 78	$ (70)
As of December 31, 2014					
Assets:					
Commodity derivatives	$ —	$ 25	$ 4	$ (11)	$ 18
Money market mutual funds[2]	23	—	—	—	23
	$ 23	$ 25	$ 4	$ (11)	$ 41
Liabilities - Commodity derivatives	$ —	$ (114)	$ —	$ 39	$ (75)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $75 million and $28 million as of December 31, 2015 and 2014, respectively.

(2) Amounts are included in other special funds and temporary cash investments on the Comparative Balance Sheet. Money market mutual funds are accounted for as available-for-sale securities and the fair value approximates cost.

Derivative contracts are recorded on the Comparative Balance Sheet as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by FERC and GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which PacifiCorp transacts. When quoted prices for identical contracts are not available, PacifiCorp uses forward price curves. Forward price curves represent PacifiCorp's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. PacifiCorp bases its forward price curves upon 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; 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 first six years. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, PacifiCorp uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The estimated fair value of these derivative contracts is a function of underlying forward commodity prices, interest rates, currency rates, related volatility, counterparty creditworthiness and duration of contracts. Refer to Note 11 for further discussion regarding PacifiCorp's risk management and hedging activities.

PacifiCorp's investments in money market mutual funds and investment funds are stated at fair value. PacifiCorp uses a readily observable quoted market price or net asset value of an identical security in an active market to record the fair value.

PacifiCorp's long-term debt is carried at cost on the Comparative Balance Sheet. The fair value of PacifiCorp's long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The carrying value of PacifiCorp's 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 value and estimated fair value of PacifiCorp's long-term debt as of December 31 (in millions):

	2015		**2014**	
	Carrying Value	**Fair Value**	**Carrying Value**	**Fair Value**
Long-term debt	$ 7,147	$ 8,210	$ 7,019	$ 8,358

(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 impact 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, penalties and other costs in substantial amounts and are described below.

USA Power

In October 2005, prior to BHE's ownership of PacifiCorp, PacifiCorp was added as a defendant to a lawsuit originally filed in February 2005 in the Third District Court of Salt Lake County, Utah ("Third District Court") by USA Power, LLC, USA Power Partners, LLC and Spring Canyon Energy, LLC (collectively, the "Plaintiff"). The Plaintiff'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 in regard to the Plaintiff's 2002 and 2003 proposals to build a natural gas-fueled generating facility in Juab County, Utah. In October 2007, the Third District Court granted PacifiCorp's motion for summary judgment on all counts and dismissed the Plaintiff's claims in their entirety. In a May 2010 ruling on the Plaintiff's petition for reconsideration, the Utah Supreme Court reversed summary judgment and remanded the case back to the Third District Court for further consideration. In May 2012, a jury awarded damages to the Plaintiff for breach of contract and misappropriation of a trade secret in the amounts of $18 million for actual damages and $113 million for unjust enrichment. After considering various motions filed by the parties to expand or limit damages, interest and attorney's fees, in May 2013, the court entered a final judgment against PacifiCorp in the amount of $115 million, which includes the $113 million of aggregate damages previously awarded and amounts awarded for the Plaintiff's attorneys' fees. The final judgment also ordered that postjudgment interest accrue beginning as of the date of the April 2013 initial judgment. In May 2013, PacifiCorp posted a surety bond issued by a subsidiary of Berkshire Hathaway to secure its estimated obligation. PacifiCorp strongly disagrees with the jury's verdict and is vigorously pursuing all appellate measures. Both PacifiCorp and the Plaintiff filed appeals with the Utah Supreme Court. Briefing before the Utah Supreme Court is complete and oral arguments were heard in September 2015. As of December 31, 2015, PacifiCorp had accrued $122 million for the final judgment and postjudgment interest, and believes the likelihood of any additional material loss is remote; however, any additional awards against PacifiCorp could also have a material effect on the financial results. Any payment of damages will be at the end of the appeals process.

Sanpete County, Utah Rangeland Fire

In June 2012, a major rangeland fire occurred in Sanpete County, Utah. Certain parties allege that contact between two of PacifiCorp's transmission lines may have triggered a ground fault that led to the fire. PacifiCorp has engaged experts to review the cause and origin of the fire, as well as to assess the damages. PacifiCorp has accrued its best estimate of the potential loss and expected insurance recovery. PacifiCorp believes it is reasonably possible it may incur additional loss beyond the amount accrued, but does not believe the potential additional loss will have a material impact on its financial results.

Environmental Laws and Regulations

PacifiCorp is subject to federal, state and local laws and regulations regarding air and water quality, renewable portfolio standards, emissions performance standards, climate change, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact PacifiCorp's current and future operations. PacifiCorp believes it is in material compliance with all applicable laws and regulations.

Hydroelectric Relicensing

PacifiCorp's Klamath hydroelectric system is currently operating under annual licenses with the FERC. In February 2010, PacifiCorp, the United States Department of the Interior, the United States Department of Commerce, the state of California, the state of Oregon and various other governmental and non-governmental settlement parties signed the Klamath Hydroelectric Settlement Agreement ("KHSA"). Among other things, the KHSA provided that the United States Department of the Interior would conduct scientific and engineering studies to assess whether removal of the Klamath hydroelectric system's mainstem dams was in the public interest and would advance restoration of the Klamath Basin's salmonid fisheries. If it was determined that dam removal should proceed, dam removal would have begun no earlier than 2020.

Under the KHSA, PacifiCorp and its customers were protected from uncapped dam removal costs and liabilities. For dam removal to occur, federal legislation consistent with the KHSA was required to provide, among other things, protection for PacifiCorp from all liabilities associated with dam removal activities. As of December 31, 2015, no federal legislation had been enacted and several parties to the KHSA initiated a dispute resolution process.

In February 2016, the principal parties to the KHSA (PacifiCorp, the states of California and Oregon, and the United States Departments of the Interior and Commerce) executed an agreement in principle committing to explore potential amendment of the KHSA to facilitate removal of the Klamath dams through a FERC process without the need for federal legislation. Since that time, PacifiCorp, the states of California and Oregon, and the United States Department of Interior and Commerce negotiated an amendment to the KHSA that was signed on April 6, 2016. Under the amended KSHA, PacifiCorp will file an application with the FERC to transfer the license for the four mainstem Klamath River hydroelectric generating facilities to a newly formed private entity, the Klamath River Renewal Corporation ("KRRC"). The KRRC will file an application to surrender the license and decommission the facilities with the FERC.

The amended KHSA provides PacifiCorp with liability protections comparable to the KHSA. The amended KHSA also limits PacifiCorp's contribution to facilities removal costs to no more than $200 million, of which up to $184 million would be collected from PacifiCorp's Oregon customers with the remainder to be collected from PacifiCorp's California customers. Additional funding of up to $250 million for facilities removal costs is to be provided by the state of California. California voters approved a water bond measure in November 2014 from which the state of California's contribution toward facilities removal costs will be drawn. If facilities removal costs exceed the combined funding that will be available from PacifiCorp's Oregon and California customers and the state of California, sufficient funds would need to be provided by the KRRC or an entity other than PacifiCorp in order for facilities removal to proceed.

If certain conditions in the amended KSHA are not satisfied and the license does not transfer to the KRRC, PacifiCorp will resume relicensing with the FERC.

Hydroelectric Commitments

Certain of PacifiCorp's hydroelectric licenses contain requirements for PacifiCorp to make certain capital and operating expenditures related to its hydroelectric facilities. PacifiCorp estimates it is obligated to make capital expenditures of approximately $252 million over the next 10 years related to these licenses.

Commitments

PacifiCorp has the following firm commitments that are not reflected on the Comparative Balance Sheet. Minimum payments as of December 31, 2015 are as follows (in millions):

	2016	2017	2018	2019	2020	2021 and Thereafter	Total
Contract type:							
Purchased electricity contracts - commercially operable	$ 168	$ 71	$ 70	$ 67	$ 68	$ 401	$ 845
Purchased electricity contracts - non-commercially operable	16	102	104	104	104	1,687	2,117
Fuel contracts	862	689	558	542	496	1,720	4,867
Construction commitments	144	12	10	2	2	5	175
Transmission	105	97	91	76	55	508	932
Operating leases and easements	5	4	4	4	4	42	63
Maintenance, service and other contracts	36	30	19	24	11	74	194
Total commitments	$ 1,336	$ 1,005	$ 856	$ 819	$ 740	$ 4,437	$ 9,193

Purchased Electricity Contracts - Commercially Operable

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 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. Included in the purchased electricity payments are any power purchase agreements that meet the definition of a lease. Rent expense related to those power purchase agreements that meet the definition of a lease totaled $13 million for 2015 and $15 million for 2014.

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 on 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 2015 and 2014 energy sources.

Purchased Electricity Contracts - Non-commercially Operable

PacifiCorp has several contracts for purchases of electricity from facilities that have not yet achieved commercial operation. To the extent any of these facilities do not achieve commercial operation, PacifiCorp has no obligation to the counterparty.

Fuel Contracts

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

Construction Commitments

PacifiCorp's construction commitments included in the table above relate to firm commitments and include costs associated with investments in emissions control equipment and certain transmission and distribution projects.

Transmission

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

Operating Leases and Easements

PacifiCorp has non-cancelable operating leases primarily for certain operating facilities, office space, land and equipment that expire at various dates through the year ending December 31, 2092. These leases generally require PacifiCorp to pay for insurance, taxes and maintenance applicable to the leased property. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. PacifiCorp also has non-cancelable easements for land on which its wind-powered generating facilities are located. Rent expense totaled $15 million for the year ended December 31, 2015 and $16 million for the year ended December 31, 2014.

Guarantees

PacifiCorp has entered into guarantees as part of the normal course of business and the sale of certain assets. These guarantees are not expected to have a material impact on PacifiCorp's financial results.

(14) Preferred Stock

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.

(15) Common Shareholder's Equity

In February 2016, PacifiCorp declared a dividend of $100 million which was paid to PPW Holdings LLC, a wholly owned subsidiary of BHE and PacifiCorp's direct parent company ("PPW Holdings") in March 2016.

Through PPW Holdings, BHE is the sole shareholder of PacifiCorp's common stock. The state regulatory orders that authorized BHE's acquisition of PacifiCorp contain restrictions on PacifiCorp's ability to pay dividends to the extent that they would reduce PacifiCorp's common equity below specified percentages of defined capitalization. As of December 31, 2015, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to PPW Holdings or BHE without prior state regulatory approval to the extent that it would reduce PacifiCorp's common equity below 44% of its total capitalization, excluding short-term debt and current maturities of long-term debt. The terms of this commitment treat 50% of PacifiCorp's remaining balance of preferred stock in existence prior to the acquisition of PacifiCorp by BHE as common equity. As of December 31, 2015, PacifiCorp's actual common equity percentage, as calculated under this measure, was 52%, and PacifiCorp would have been permitted to dividend $2.0 billion under this commitment.

These commitments also restrict PacifiCorp from making any distributions to either PPW Holdings or BHE if PacifiCorp's senior 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, 2015, PacifiCorp met the minimum required senior unsecured debt ratings for making distributions.

PacifiCorp is also subject to a maximum debt-to-total capitalization percentage under various financing agreements as further discussed in Note 6.

(16) Supplemental Cash Flow Disclosures

The summary of supplemental cash flow disclosures as of and for the years ended December 31 is as follows (in millions):

	2015	2014
Interest paid, net of amounts capitalized	$ 342	$ 340
Income taxes paid, net(1)	$ 32	$ 154
Supplemental disclosure of non-cash investing and financing activities:		
Accounts payable related to utility plant additions	$ 147	$ 140
Accounts receivable related to utility plant sales	$ 10	$ —

(1) PacifiCorp is party to a tax-sharing agreement and is part of the Berkshire Hathaway United States federal income tax return. Amounts substantially represent income taxes received from or paid to BHE.

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.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				(9,091,505)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				346,579
3	Preceding Quarter/Year to Date Changes in Fair Value				(4,920,754)
4	Total (lines 2 and 3)				(4,574,175)
5	Balance of Account 219 at End of Preceding Quarter/Year				(13,665,680)
6	Balance of Account 219 at Beginning of Current Year				(13,665,680)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				549,221
8	Current Quarter/Year to Date Changes in Fair Value				1,101,821
9	Total (lines 7 and 8)				1,651,042
10	Balance of Account 219 at End of Current Quarter/Year				(12,014,638)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			(9,091,505)		
2			346,579		
3			(4,920,754)		
4			(4,574,175)	697,859,628	693,285,453
5			(13,665,680)		
6			(13,665,680)		
7			549,221		
8			1,101,821		
9			1,651,042	695,335,538	696,986,580
10			(12,014,638)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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 (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	26,338,511,410	26,338,511,410
4	Property Under Capital Leases	32,269,865	32,269,865
5	Plant Purchased or Sold	2,021,782	2,021,782
6	Completed Construction not Classified	178,083,508	178,083,508
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	26,550,886,565	26,550,886,565
9	Leased to Others		
10	Held for Future Use	23,319,217	23,319,217
11	Construction Work in Progress	628,213,113	628,213,113
12	Acquisition Adjustments	154,931,754	154,931,754
13	Total Utility Plant (8 thru 12)	27,357,350,649	27,357,350,649
14	Accum Prov for Depr, Amort, & Depl	9,237,522,532	9,237,522,532
15	Net Utility Plant (13 less 14)	18,119,828,117	18,119,828,117
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	8,565,801,806	8,565,801,806
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	559,800,280	559,800,280
22	Total In Service (18 thru 21)	9,125,602,086	9,125,602,086
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	111,920,446	111,920,446
33	Total Accum Prov (equals 14) (22,26,30,31,32)	9,237,522,532	9,237,522,532

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
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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 (2) [ ] A Resubmission	/ /	End of 2015/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	206,918,794	55,991
4	(303) Miscellaneous Intangible Plant	673,276,331	24,205,162
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	880,195,125	24,261,153
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	93,605,464	47,987
9	(311) Structures and Improvements	1,016,964,547	18,702,737
10	(312) Boiler Plant Equipment	4,241,159,623	238,183,284
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	996,174,043	17,716,957
13	(315) Accessory Electric Equipment	491,994,671	2,559,657
14	(316) Misc. Power Plant Equipment	31,176,256	176,739
15	(317) Asset Retirement Costs for Steam Production	56,579,908	89,146,747
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	6,927,654,512	366,534,108
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	31,316,716	
28	(331) Structures and Improvements	246,835,680	16,242,098
29	(332) Reservoirs, Dams, and Waterways	481,948,519	8,166,920
30	(333) Water Wheels, Turbines, and Generators	126,979,854	2,130,269
31	(334) Accessory Electric Equipment	77,521,376	4,853,291
32	(335) Misc. Power PLant Equipment	2,375,380	8,928
33	(336) Roads, Railroads, and Bridges	20,500,603	1,720,983
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	987,478,128	33,122,489
36	D. Other Production Plant		
37	(340) Land and Land Rights	43,017,819	1,756,736
38	(341) Structures and Improvements	226,915,569	607,659
39	(342) Fuel Holders, Products, and Accessories	15,869,834	194,191
40	(343) Prime Movers	2,899,836,969	87,055,026
41	(344) Generators	471,641,816	5,065,733
42	(345) Accessory Electric Equipment	325,607,171	982,837
43	(346) Misc. Power Plant Equipment	15,102,112	819,853
44	(347) Asset Retirement Costs for Other Production	9,474,651	4,502,488
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	4,007,465,941	100,984,523
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	11,922,598,581	500,641,120

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

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

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

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
			206,974,785		3
27,427,563		-296,242	669,757,688		4
27,427,563		-296,242	876,732,473		5
					6
					7
9,837		-87,288	93,556,326		8
23,924,121		-45,298	1,011,697,865		9
103,167,884		-1,260,711	4,374,914,312		10
					11
59,790,631		77,526	954,177,895		12
10,846,311		1,000,767	484,708,784		13
201,769		124,182	31,275,408		14
167,776	-3,897,507		141,661,372		15
198,108,329	-3,897,507	-190,822	7,091,991,962		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
3,785			31,312,931		27
399,258		-164,236	262,514,284		28
1,669,211		-43,767	488,402,461		29
190,865			128,919,258		30
2,555,131			79,819,536		31
251		-3,274	2,380,783		32
57,872		6,895	22,170,609		33
					34
4,876,373		-204,382	1,015,519,862		35
					36
635			44,773,920		37
83,632		149,751	227,589,347		38
159,729			15,904,296		39
57,816,710		948,488	2,930,023,773		40
2,314,216		-916,710	473,476,623		41
314,011		-19,457	326,256,540		42
		-378	15,921,587		43
	-945,784		13,031,355		44
60,688,933	-945,784	161,694	4,046,977,441		45
263,673,635	-4,843,291	-233,510	12,154,489,265		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	230,226,403	17,839,900
49	(352) Structures and Improvements	210,430,141	20,077,892
50	(353) Station Equipment	1,875,788,731	155,302,132
51	(354) Towers and Fixtures	1,221,298,019	67,458,271
52	(355) Poles and Fixtures	744,102,993	158,276,662
53	(356) Overhead Conductors and Devices	1,082,532,470	109,294,243
54	(357) Underground Conduit	3,519,566	
55	(358) Underground Conductors and Devices	8,035,354	
56	(359) Roads and Trails	11,937,200	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	5,387,870,877	528,249,100
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	63,135,433	1,379,309
61	(361) Structures and Improvements	104,255,048	3,093,921
62	(362) Station Equipment	925,759,498	38,711,222
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	1,085,444,520	39,717,972
65	(365) Overhead Conductors and Devices	707,873,785	17,703,989
66	(366) Underground Conduit	341,230,913	10,139,125
67	(367) Underground Conductors and Devices	795,524,274	24,731,953
68	(368) Line Transformers	1,234,715,959	47,383,609
69	(369) Services	679,839,675	30,420,165
70	(370) Meters	180,902,129	8,823,758
71	(371) Installations on Customer Premises	8,831,952	103,069
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	61,371,460	1,174,632
74	(374) Asset Retirement Costs for Distribution Plant	1,507,080	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	6,190,391,726	223,382,724
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	21,396,610	
87	(390) Structures and Improvements	239,006,029	5,133,404
88	(391) Office Furniture and Equipment	82,750,840	8,903,086
89	(392) Transportation Equipment	107,071,045	6,751,977
90	(393) Stores Equipment	14,910,200	396,647
91	(394) Tools, Shop and Garage Equipment	62,963,632	2,288,604
92	(395) Laboratory Equipment	33,940,714	2,027,929
93	(396) Power Operated Equipment	163,759,938	12,043,147
94	(397) Communication Equipment	408,492,593	18,293,981
95	(398) Miscellaneous Equipment	8,038,720	623,306
96	SUBTOTAL (Enter Total of lines 86 thru 95)	1,142,330,321	56,462,081
97	(399) Other Tangible Property	302,661,738	103,342
98	(399.1) Asset Retirement Costs for General Plant	39,748	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	1,445,031,807	56,565,423
100	TOTAL (Accounts 101 and 106)	25,826,088,116	1,333,099,520
101	(102) Electric Plant Purchased (See Instr. 8)		33,944,495
102	(Less) (102) Electric Plant Sold (See Instr. 8)		-1,114,497
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	25,826,088,116	1,368,158,512

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
20,561		3,580,225	251,625,967		48
981,258		9,778,458	239,305,233		49
10,809,876		-7,489,910	2,012,791,077		50
441,842		677,369	1,288,991,817		51
2,205,326		1,125,206	901,299,535		52
1,802,218		3,226,200	1,193,250,695		53
			3,519,566		54
			8,035,354		55
			11,937,200		56
					57
16,261,081		10,897,548	5,910,756,444		58
					59
661		-2,052,930	62,461,151		60
633,455		3,534,798	110,250,312		61
5,145,598		12,351,300	971,676,422		62
					63
5,003,239		595,956	1,120,755,209		64
1,721,048		212,303	724,069,029		65
1,679,949			349,690,089		66
2,759,203		2,683,874	820,180,898		67
9,230,679		1,265,192	1,274,134,081		68
731,583			709,528,257		69
2,789,132			186,936,755		70
71,971			8,863,050		71
					72
1,323,307			61,222,785		73
			1,507,080		74
31,089,825		18,590,493	6,401,275,118		75
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					83
					84
					85
15,233		100,073	21,481,450		86
5,095,708		1,161,730	240,205,455		87
11,483,612		385,964	80,556,278		88
4,058,393		887,811	110,652,440		89
218,682		90,651	15,178,816		90
1,418,459		228,074	64,061,851		91
2,800,420		793,553	33,961,776		92
7,927,524		389,583	168,265,144		93
528,176		1,985,549	428,243,947		94
540,386		13,960	8,135,600		95
34,086,593		6,036,948	1,170,742,757		96
297,230,126		-2,975,841	2,559,113		97
			39,748		98
331,316,719		3,061,107	1,173,341,618		99
669,768,823	-4,843,291	32,019,396	26,516,594,918		100
	20,744	-32,504,781	1,460,458		101
		553,173	-561,324		102
					103
669,768,823	-4,822,547	-1,038,558	26,518,616,700		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	$ -	$ 75,803	$ -	$ -	$2,559,113
39922	Land Rights	52,550,647	-	52,550,647	-	-	-
39930	Structures	43,930,324	34,802	42,812,678	-	(1,152,448)	-
39941	Surface-Plant Equipment	14,435,529	-	14,435,529	-	-	-
39944	Surface-Electric Pwr Facil	3,424,575	-	3,424,575	-	-	-
39945	Underground-Coal Mine Equip	71,384,906	-	71,384,906	-	-	-
39946	Longwall Shields	24,486,688	-	24,486,688	-	-	-
39947	Longwall Equipment	9,115,912	-	9,115,912	-	-	-
39948	Mainline Extension	20,274,157	-	20,274,157	-	-	-
39949	Section Extension	7,386,842	-	7,386,842	-	-	-
39951	Vehicles	1,321,430	-	788,378	-	(533,052)	-
39952	Heavy Construction Equip	6,023,975	-	5,902,004	-	(121,971)	-
39960	Miscellaneous General Equip	2,364,325	71,846	1,376,701	-	(1,059,470)	-
39961	Computers-Mainframe	467,717	(3,306)	355,511	-	(108,900)	-
39970	Mine Development & Road Ext	38,657,119	-	38,657,119	-	-	-
39915	Coal Mine ARO	4,202,676	-	4,202,676	-	-	-
		$ 302,661,738	$ 103,342	$297,230,126	$ -	$(2,975,841)	$2,559,113

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

Refer to Important Changes During the Year, Item 3, in this Form No. 1.

Schedule Page: 204 Line No.: 101 Column: e

Account 114, Electric plant acquisition adjustments

Schedule Page: 204 Line No.: 101 Column: f

Refer to Important Changes During the Year, Item 3, in this Form No. 1.

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

Refer to Important Changes During the Year, Item 3, in this Form No. 1.

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

Refer to Important Changes During the Year, Item 3, in this Form No. 1.

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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	North Horn Mountain Coal Properties	1977	2023-2028	953,014
3	Barnes Butte Substation	2007	2025	746,268
4	Wild Horse Wind Plant	2007	2028	6,763,094
5	Twelve Mile Wind Plant	2007	2028	2,160,207
6	Jumbers Point Substation	2008	2022	1,173,276
7	Mountain Green Substation	2009	2025	284,996
8	Hoggard Substation	2009	2025	254,397
9	Oquirrh-Terminal 345kV Transmission Line	2009	2021	396,020
10	Bend Service Center	2010	2022	3,507,838
11	Legacy Substation	2010	2025	562,276
12	Aeolus Substation	2011	2021	1,013,577
13	Anticline Substation	2011	2024	964,043
14	Populus Substation	2011	2024	254,753
15	Snyderville Substation	2011	2017	253,401
16	Lassen Substation	2012	2017	683,318
17	Old Mill Substation	2012	2020	1,838,281
18	Chimney Butte-Paradise 230kV Transmission Line	2013	2018	598,457
19	Miscellaneous, each under $250,000:			912,001
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
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46				
47	Total			23,319,217

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) X An Original (2) _ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 214 Line No.: 2 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.: 4 Column: c

Land purchased for wind farms with an estimated construction date of 2028, subject to environmental and economic reviews and the timing of completion of the Energy Gateway Transmission Expansion Program.

Schedule Page: 214 Line No.: 5 Column: c

Land purchased for wind farms with an estimated construction date of 2028, subject to environmental and economic reviews and the timing of completion of the Energy Gateway Transmission Expansion Program.

Schedule Page: 214 Line No.: 19 Column: c

Various dates and plans.

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Intangible:	
2	EMS/SCADA Replacement / Upgrade	28,544,601
3	Wallowa Falls Hydro Relicensing	2,465,534
4	Spectrum License Buildout	2,215,433
5	EMS PI Upgrade	1,087,932
6		
7	Production:	
8	Jim Bridger U4 Selective Catalytic Reduction System	78,314,299
9	Craig U2 Selective Catalytic Reduction System	14,677,256
10	Hayden U2 Selective Catalytic Reduction System	7,162,006
11	Chehalis Combustion Turbine 2 Compressor Replace	5,756,834
12	Lewis River System Relicensing Implementation	4,842,074
13	Hunter U3 Cooling Tower Replacement	4,762,088
14	Hunter U3 Generator Stator Rewind	3,405,586
15	Cholla U4 Mercury Reduction	2,852,299
16	Jim Bridger U4 Replace Finishing Superheater	2,833,706
17	Hunter U3 Generator Excitation System	2,327,415
18	Hunter U3 Submerged Drag Chain Conveyor	2,297,272
19	Hunter U3 Baghouse Bags	1,496,458
20	Dave Johnston Replace Ash Silo Flat Bottom with Cone	1,394,450
21	Toketee Dam Rehabilitation Evaluation	1,342,232
22	Last Chance Dam Rebuild	1,074,597
23		
24	Transmission:	
25	Aeolus - Clover 500kV Line	72,524,742
26	Windstar - Populus 230 - 500kV Line	66,658,132
27	Boardman - Hemingway 500kV Line	45,264,515
28	Populus - Hemingway 500kV Line	44,830,945
29	Standpipe Substation New 230kV Substation	20,034,832
30	Union Gap Substation Add 230 - 115kV Capacity	18,117,077
31	Pinto Substation Add 3rd Phase Shifting Transformer	15,103,401
32	Snow Goose 500 - 230kV Substation	14,424,395
33	Oquirrh - Terminal 345kV Line	10,975,575
34	Vantage - Pomona Heights 230kV Line	8,781,178
35	West Point - New 138kV Line and 40 MVA Substation	8,449,489
36	Southwest WY - Silver Creek Build 138kV Line	4,725,345
37	Wallula - McNary 230kV Line	3,722,678
38	Chehalis U3 Generator Step-Up Transformer Replacement	3,637,221
39	Weed Substation 115 - 69kV LTC Transformer	3,599,747
40	Troutdale Substation 230kV Switchyard 115kV Ring Bus	2,900,867
41	Lincoln - Harrison 115kV Line Joint PGE Modifications	1,674,624
42	Sigurd - Red Butte - Crystal 345kV Line	1,648,115
43	TOTAL	628,213,113

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Captain Jack - Snow Goose Replace 500kV Relays	1,350,983
2	Purgatory Flat New 138kV Substation	1,328,268
3	RMP Spare 161 - 138kV 200 MVA Transformer	1,302,112
4		
5	Distribution:	
6	River Road Substation 25 MVA Transformer	2,878,046
7	NE Portland Voltage Conversion Project	2,518,766
8	Stadelman Fruit, Yakima WA	1,494,267
9	Lassen Substation - New Substation	1,009,306
10		
11	Miscellaneous Projects each under $1,000,000	100,406,415
12		
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42		
43	TOTAL	628,213,113

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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	8,395,189,232	8,395,189,232		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	697,031,280	697,031,280		
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):	40,650,578	40,650,578		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	737,681,858	737,681,858		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	634,661,285	634,661,285		
13	Cost of Removal	56,702,091	56,702,091		
14	Salvage (Credit)	5,459,746	5,459,746		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	685,903,630	685,903,630		
16	Other Debit or Cr. Items (Describe, details in footnote):	118,834,346	118,834,346		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	8,565,801,806	8,565,801,806		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	2,886,821,179	2,886,821,179		
21	Nuclear Production				
22	Hydraulic Production-Conventional	327,988,750	327,988,750		
23	Hydraulic Production-Pumped Storage				
24	Other Production	847,165,096	847,165,096		
25	Transmission	1,503,737,225	1,503,737,225		
26	Distribution	2,581,141,819	2,581,141,819		
27	Regional Transmission and Market Operation				
28	General	418,947,737	418,947,737		
29	TOTAL (Enter Total of lines 20 thru 28)	8,565,801,806	8,565,801,806		

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

Generally, 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, until consumed	$ 9,600,027
Account 143, Other accounts receivable: depreciation expense billed to joint owners	281,680
Asset retirement obligation asset depreciation recorded as a regulatory asset or liability	10,416,034
Deferral of Carbon depreciation recorded as a regulatory asset	3,372,072
Deferral of increased depreciation, due to depreciation study rates, net of amortization, recorded as a regulatory asset	1,099,236
Transportation depreciation charged to operations and maintenance expense and construction work in progress based on usage activity	14,214,593
Account 503, Steam from other sources: Blundell depletion	185,368
Account 503, Steam from other sources: Blundell depreciation	1,481,568
Total Other Accounts	$ 40,650,578

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

Reclassification of accrued removal and spend on asset retirement obligations that were included in lines 3 and 13	$ 5,928,266
Other items include: - Utah mine disposition - Recovery from third parties for asset relocations and damaged property - Insurance recoveries - Adjustments of reserve related to electric plant sold and/or purchased - Reclassifications from electric plant	112,906,079
Total Other Debit or Cr. Items	$118,834,346

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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.	1973		
2	Common Stock			1
3	Paid-in Capital			47,960,000
4	Undistributed Subsidiary Earnings			135,509,939
5	SUBTOTAL			183,469,940
6				
7	ENERGY WEST MINING COMPANY	1990		
8	Common Stock			1,000
9	SUBTOTAL			1,000
10				
11	GLENROCK COAL COMPANY	1991		
12	Common Stock			1
13	SUBTOTAL			1
14				
15	INTERWEST MINING COMPANY	1992		
16	Common Stock			1,000
17	SUBTOTAL			1,000
18				
19	TRAPPER MINING INC.	1992		
20	Members' Equity			6,038,000
21	Undistributed Subsidiary Earnings			6,652,381
22	SUBTOTAL			12,690,381
23				
24	FOSSIL ROCK FUELS, LLC	2011		
25	Paid-in Capital			31,322,429
26	Undistributed Subsidiary Earnings			-13,673
27	SUBTOTAL			31,308,756
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 85,538,430		TOTAL	227,471,078

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
13,258,734		148,768,673		4
13,258,734		196,728,674		5
				6
				7
		1,000		8
		1,000		9
				10
				11
		1		12
		1		13
				14
				15
		1,000		16
		1,000		17
				18
				19
		6,038,000		20
445,700		7,010,024		21
445,700		13,048,024		22
				23
				24
		31,538,428		25
-159,485		-173,158		26
-159,485		31,365,270		27
				28
				29
				30
				31
				32
				33
				34
				35
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				41
13,544,949		241,143,969		42

Schedule Page: 224 Line No.: 1 Column: a

Pacific Minerals, Inc. is a wholly owned subsidiary of PacifiCorp that holds a two-thirds ownership interest in Bridger Coal Company, a coal-mining joint venture with Idaho Energy Resources Company, a subsidiary of Idaho Power Company.

Schedule Page: 224 Line No.: 21 Column: g

In September 2015, Trapper Mining Inc., a subsidiary of PacifiCorp, paid a dividend of $88,057 to PacifiCorp.

Schedule Page: 224 Line No.: 25 Column: g

In 2015, PacifiCorp contributed $216,000 to its wholly owned subsidiary, Fossil Rock Fuels, LLC.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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)	198,515,639	192,305,988	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)	111,221,100	134,703,542	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	94,012,733	84,947,332	Electric
8	Transmission Plant (Estimated)	490,752	653,625	Electric
9	Distribution Plant (Estimated)	12,319,645	12,772,256	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	5,593,971	55,338	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	223,638,201	233,132,093	
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)	422,153,840	425,438,081	

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

Mining materials and supplies	$ 5,512,384
General plant materials and supplies	81,587
	$ 5,593,971

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

General plant materials and supplies	$ 55,338

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2016 No. (d)	2016 Amt. (e)
1	Balance-Beginning of Year	443,349.00		149,627.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	34,135.00			
19	Other:				
20	Prior Period Adjustments				
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	409,214.00		149,627.00	
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 (2) [ ] A Resubmission	/ /	End of 2015/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.

2017		2018		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
151,733.00		156,646.00		4,067,534.00		4,968,889.00		1
								2
								3
								4
				156,645.00		156,645.00		5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						34,135.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
151,733.00		156,646.00		4,224,179.00		5,091,399.00		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

Schedule Page: 228   Line No.: 18   Column: b

Includes an adjustment to the balance at beginning of year.

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	Q1898			7,008	456
3	Q1799	236	561.6	236	456
4	Q1803	703	561.6	703	456
5	Q1917	852	561.6	852	456
6	Q1918	43,838	561.6	43,838	456
7	Q1919	12,110	561.6	12,110	456
8	Q1977	2,712	561.6	2,712	456
9	Q1937a	922	561.6	922	456
10	Q1937b	1,865	561.6	1,865	456
11	Q1937c	638	561.6	638	456
12	Q1948	355	561.6	355	456
13	AREF 79456228	89	561.6		
14	AREF 79657068	357	561.6		
15	AREF 79857385	2,582	561.6		
16	AREF 79857389	573	561.6		
17	AREF 80149329	1,312	561.6		
18	AREF 80994031	6,732	561.6		
19	AREF 81045929	1,575	561.6		
20	AREF 81045934	9,007	561.6		
21	**Generation Studies**				
22	GIQ0139	1,233	561.7	1,233	456
23	GIQ0252	538	561.7	538	456
24	GIQ0316	830	561.7	830	456
25	GIQ0335	10,973	561.7	10,973	456
26	GIQ0397	4,933	561.7	4,933	456
27	GIQ0409	6,853	561.7	6,853	456
28	GIQ0443	1,327	561.7	1,327	456
29	GIQ0451	2,692	561.7	2,692	456
30	GIQ0456	2,621	561.7	2,621	456
31	GIQ0463	5,148	561.7	5,148	456
32	GIQ0465	147	561.7	147	456
33	GIQ0471	1,104	561.7	1,104	456
34	GIQ0472	850	561.7	850	456
35	GIQ0473	776	561.7	776	456
36	GIQ0503	2,363	561.7	2,363	456
37	GIQ0504	1,599	561.7	1,599	456
38	GIQ0509	220	561.7	220	456
39	GIQ0510	441	561.7	441	456
40	GIQ0513	2,174	561.7	2,174	456

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 81074553	3,250	561.6		
3	AREF 81235956	1,846	561.6		
4	AREF 81235960	784	561.6		
5	AREF 81269101	1,337	561.6		
6	AREF 81269111	922	561.6		
7	AREF 81287437	1,199	561.6		
8	AREF 81288775	185	561.6		
9	AREF 81288790	694	561.6		
10	AREF 81288866	830	561.6		
11	AREF 81315991	1,017	561.6		
12	AREF 81316049	138	561.6		
13	AREF 81316106	1,708	561.6		
14	AREF 81316143	1,017	561.6		
15	AREF 81369194	1,201	561.6		
16	AREF 81460501	2,352	561.6		
17	AREF 81550387	284	561.6		
18		3,424	561.6		
19	Customer Studies Accruals	(2,335)	561.6		
20					
21	**Generation Studies**				
22	GIQ0516	150	561.7	150	456
23	GIQ0518	3,715	561.7	3,715	456
24	GIQ0519	3,871	561.7	3,871	456
25	GIQ0520	3,733	561.7	3,733	456
26	GIQ0521	3,484	561.7	3,484	456
27	GIQ0524	768	561.7	768	456
28	GIQ0529	1,784	561.7	1,784	456
29	GIQ0530	1,836	561.7	1,836	456
30	GIQ0531	2,024	561.7	2,024	456
31	GIQ0532	2,291	561.7	2,291	456
32	GIQ0539	3,468	561.7	3,468	456
33	GIQ0542	9,036	561.7	9,036	456
34	GIQ0543	996	561.7	996	456
35	GIQ0547	1,935	561.7	1,935	456
36	GIQ0551	38	561.7	38	456
37	GIQ0555	958	561.7	958	456
38	GIQ0556	1,265	561.7	1,265	456
39	GIQ0558	5,389	561.7	5,389	456
40	GIQ0560	1,295	561.7	1,295	456

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	GIQ0562	2,935	561.7	2,935	456
23	GIQ0563	2,542	561.7	2,542	456
24	GIQ0564	8,461	561.7	8,461	456
25	GIQ0566	5,644	561.7	5,644	456
26	GIQ0571	1,095	561.7	1,095	456
27	GIQ0572	1,251	561.7	1,251	456
28	GIQ0573	3,038	561.7	3,038	456
29	GIQ0577	10,377	561.7	10,377	456
30	GIQ0578	6,594	561.7	6,594	456
31	GIQ0579	294	561.7	294	456
32	GIQ0580	7,584	561.7	7,584	456
33	GIQ0581	37	561.7	37	456
34	GIQ0582	13,149	561.7	13,149	456
35	GIQ0585	6,799	561.7	6,799	456
36	GIQ0586	17,530	561.7	17,530	456
37	GIQ0587	9,999	561.7	9,999	456
38	GIQ0589	17,525	561.7	17,525	456
39	GIQ0592	1,078	561.7	1,078	456
40	GIQ0593	7,776	561.7	7,776	456

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	GIQ0594	15,745	561.7	15,745	456
23	GIQ0597	2,359	561.7	2,359	456
24	GIQ0598	4,599	561.7	4,599	456
25	GIQ0600	5,711	561.7	5,711	456
26	GIQ0603	16,475	561.7	16,475	456
27	GIQ0604	5,447	561.7	5,447	456
28	GIQ0605	37	561.7	37	456
29	GIQ0606	3,140	561.7	3,140	456
30	GIQ0607	4,704	561.7	4,704	456
31	GIQ0608	37	561.7	37	456
32	GIQ0609	9,253	561.7	9,253	456
33	GIQ0611	4,105	561.7	4,105	456
34	GIQ0612	8,834	561.7	8,834	456
35	GIQ0613	9,097	561.7	9,097	456
36	GIQ0614	4,761	561.7	4,761	456
37	GIQ0616	4,950	561.7	4,950	456
38	GIQ0617	13,036	561.7	13,036	456
39	GIQ0618	11,038	561.7	11,038	456
40	GIQ0620	11,734	561.7	11,734	456

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	GIQ0621	14,151	561.7	14,151	456
23	GIQ0622	7,581	561.7	7,581	456
24	GIQ0623	4,585	561.7	4,585	456
25	GIQ0624	6,968	561.7	6,968	456
26	GIQ0625	890	561.7	890	456
27	GIQ0626	37	561.7	37	456
28	GIQ0627	16,810	561.7	16,810	456
29	GIQ0628	220	561.7	220	456
30	GIQ0629	12,570	561.7	12,570	456
31	GIQ0630	245	561.7	245	456
32	GIQ0631	14,339	561.7	14,339	456
33	GIQ0632	12,286	561.7	12,286	456
34	GIQ0633	1,202	561.7	1,202	456
35	GIQ0634	35,246	561.7	35,246	456
36	GIQ0635	2,694	561.7	2,694	456
37	GIQ0636	33,366	561.7	33,366	456
38	GIQ0637	1,306	561.7	1,306	456
39	GIQ0638	7,714	561.7	7,714	456
40	GIQ0639	5,085	561.7	5,085	456

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	GIQ0640	11,964	561.7	11,964	456
23	GIQ0641	18,819	561.7	18,819	456
24	GIQ0642	23,651	561.7	23,651	456
25	GIQ0643	6,821	561.7	6,821	456
26	GIQ0644	(1)	561.7	(1)	456
27	GIQ0645	6,450	561.7	6,450	456
28	GIQ0646	2,154	561.7	2,154	456
29	GIQ0647	23,974	561.7	23,974	456
30	GIQ0648	12,841	561.7	12,841	456
31	GIQ0649	10,100	561.7	10,100	456
32	GIQ0650	19,652	561.7	19,652	456
33	GIQ0651	4,966	561.7	4,966	456
34	GIQ0652	4,965	561.7	4,965	456
35	GIQ0653	4,298	561.7	4,298	456
36	GIQ0654	8,301	561.7	8,301	456
37	GIQ0655	12,163	561.7	12,163	456
38	GIQ0656	16,220	561.7	16,220	456
39	GIQ0657	4,379	561.7	4,379	456
40	GIQ0658	2,173	561.7	2,173	456

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	GIQ0659	15,328	561.7	15,328	456
23	GIQ0660	11,605	561.7	11,605	456
24	GIQ0661	15,593	561.7	15,593	456
25	GIQ0662	17,576	561.7	17,576	456
26	GIQ0663	4,500	561.7	4,500	456
27	GIQ0664	4,677	561.7	4,677	456
28	GIQ0665	2,985	561.7	2,985	456
29	GIQ0666	12,124	561.7	12,124	456
30	GIQ0667	4,843	561.7	4,843	456
31	GIQ0668	3,378	561.7	3,378	456
32	GIQ0669	9,131	561.7	9,131	456
33	GIQ0670	13,060	561.7	13,060	456
34	GIQ0671	13,760	561.7	13,760	456
35	GIQ0672	14,736	561.7	14,736	456
36	GIQ0674	420	561.7	420	456
37	GIQ0675	828	561.7	828	456
38	GIQ0676	989	561.7	989	456
39	GIQ0677	1,611	561.7	1,611	456
40	GIQ0678	9,724	561.7	9,724	456

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	GIQ0679	6,603	561.7	6,603	456
23	GIQ0680	975	561.7	975	456
24	GIQ0681	737	561.7	737	456
25	GIQ0682	13,215	561.7	13,215	456
26	GIQ0683	165	561.7	165	456
27	GIQ0684	15,073	561.7	15,073	456
28	GIQ0685	110	561.7	110	456
29	GIQ0686	5,599	561.7	5,599	456
30	GIQ0687	3,765	561.7	3,765	456
31	GIQ0688	1,066	561.7	1,066	456
32	GIQ0689	927	561.7	927	456
33	GIQ0690	854	561.7	854	456
34	GIQ0691	664	561.7	664	456
35	GIQ0692	1,029	561.7	1,029	456
36	GIQ0693	692	561.7	692	456
37	GIQ0694	692	561.7	692	456
38	GIQ0695	692	561.7	692	456
39	GIQ0696	695	561.7	695	456
40	GIQ0697	1,248	561.7	1,248	456

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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					
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20					
21	**Generation Studies**				
22	GIQ0698	1,156	561.7	1,156	456
23	GIQ0699	889	561.7	889	456
24	GIQ0700	711	561.7	711	456
25	GIQ0701	1,183	561.7	1,183	456
26	GIQ0702	9,329	561.7	9,329	456
27	GIQ0703	10,219	561.7	10,219	456
28	GIQ0704	6,959	561.7	6,959	456
29	GIQ0705	1,252	561.7	1,252	456
30	GIQ0706	1,201	561.7	1,201	456
31	GIQ0707	833	561.7	833	456
32	GIQ0708	851	561.7	851	456
33	GIQ0709	1,303	561.7	1,303	456
34	GIQ0710	2,672	561.7	2,672	456
35	GIQ0711	2,366	561.7	2,366	456
36	GIQ0712	1,279	561.7	1,279	456
37	GIQ0713	1,128	561.7	1,128	456
38	GIQ0714	2,530	561.7	2,530	456
39	GIQ0715	2,424	561.7	2,424	456
40	GIQ0716	2,663	561.7	2,663	456

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	GIQ0717	484	561.7	484	456
23	GIQ0718	941	561.7	941	456
24	GIQ0719	1,244	561.7	1,244	456
25	GIQ0720	1,227	561.7	1,227	456
26	GIQ0721	1,189	561.7	1,189	456
27	GIQ0722	797	561.7	797	456
28	GIQ0723	490	561.7	490	456
29	Pre-Application Studies - East	2,895	561.7	2,895	456
30	Pre-Application Studies - West	10,003	561.7	10,003	456
31	Q0583	6,789	561.7		0
32	Customer Studies Accruals	(15,190)	561.7		0
33			0		0
34			0		0
35			0		0
36			0		0
37			0		0
38			0		0
39			0		0
40			0		0

Schedule Page: 231 Line No.: 2 Column: d

Reimbursements received in 2015 for costs incurred during 2014.

Schedule Page: 231.1 Line No.: 18 Column: a

Other Transmission Project Queue #0113

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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 $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS 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	DSM Balancing Account - CA	1,166,810	2,458,950	908,431	2,768,936	856,824
2	DSM Balancing Account - ID	744,888	4,202,714	908,431	4,039,527	908,075
3	DSM Balancing Account - UT	18,414,133	63,084,271	908	67,228,493	14,269,911
4	DSM Balancing Account - WA	1,078,059	11,374,452	908	10,509,237	1,943,274
5	DSM Balancing Account - WY		323,788			323,788
6	Deferred Excess Net Power Costs - CA	7,094,731	3,189,288	555	3,888,191	6,395,828
7	Deferred Excess Net Power Costs - ID	25,605,859	16,993,412	555	20,202,740	22,396,531
8	Deferred Excess Net Power Costs - UT	63,084,452	19,099,561	555	41,755,669	40,428,344
9	Deferred Excess Net Power Costs - WY	26,163,378	9,587,053	555	19,330,406	16,420,025
10	Deferred Excess RECs in Rates - UT	19,001,916	128,673	456	7,776,194	11,354,395
11	Deferred Excess RECs/SO2 in Rates - WY	2,207,437	191,924	456	1,785,479	613,882
12	Deferred Excess RECs in Rates - WA	4,917,237		456,419	1,747,360	3,169,877
13	Income Tax Reg. Asset - WA Flow Through	254,760		410.1	254,760	
14	Deferred Income Tax Electric	446,017,017	2,002,691	282,283	11,149,689	436,870,019
15	Solar ITC Basis Adjustment Regulatory Asset	82,313	330	282,283	3,907	78,736
16	Tax Adj on Postretirement Benefits - OR (5)	2,682,984		410.1	894,329	1,788,655
17	Tax Adj on Postretirement Benefits - WY (4)	1		410.1	1	
18	Tax Revenue Requirement Adjustment - WY (4)	22,041			17,633	4,408
19	Pension	473,546,816	40,283,016		40,501,178	473,328,654
20	Other Postretirement	16,758,010	16,965,127		7,954,629	25,768,508
21	Postemployment Costs	8,361,445			4,944,224	3,417,221
22	Powerdale Decommissioning - ID (10)	156,362		407.3	26,216	130,146
23	Carbon Plant Regulatory Asset - ID (6)	2,106,371	605,914	403	319,092	2,393,193
24	Carbon Plant Regulatory Asset - UT (6)	14,599,216	4,920,417	403	2,296,427	17,223,206
25	Carbon Plant Regulatory Asset - WY (6)	5,329,679	1,589,163	403	1,127,903	5,790,939
26	Depreciation Study Deferral - ID	1,589,451	1,669,470			3,258,921
27	Depreciation Study Deferral - UT (17)	2,112,712		403	128,043	1,984,669
28	Depreciation Study Deferral - WY (17)	7,296,150		403	442,191	6,853,959
29	Generating Plant Liquidated Damages - WY	1,407,280		930.2	54,288	1,352,992
30	Generating Plant Liquidated Damages - UT	665,000		930.2	35,000	630,000
31	Chehalis Generating Facility Deferral - WA (6)	3,000,000			3,000,000	
32	Klamath Hydroelectric Relicensing Costs - UT (10)	29,170,485	1,483,296	404	4,483,442	26,170,339
33	Cholla Plant Transaction Costs (26)	2,424,799		557	938,633	1,486,166
34	Washington Colstrip Unit No. 3 (22)	317,507		456	52,188	265,319
35	Naughton Unit No. 3 Environmental Costs - CA (2)	51,021		407	51,021	
36	Naughton Unit No. 3 Environmental Costs - ID (2)	239,494		407	239,494	
37	Environmental Costs (10)	40,073,889	7,381,454	253,925	2,963,445	44,491,898
38	Asset Retirement Obligations Regulatory Difference	51,344,265	13,753,167			65,097,432
39	Unamortized Contract Values	123,014,796		242	12,942,849	110,071,947
40	Unrealized Loss on Derivative Contracts	85,415,690	47,126,620			132,542,310
41	Greenhouse Gas Allowance Compliance Costs - CA	5,110,660	6,439,770	555	10,753,805	796,625
42	Solar Feed-In Tariff Deferral - OR (1)	5,021,117	5,000,926		4,685,939	5,336,104
43	Solar Incentive Program - UT		21,683			21,683

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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 $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS 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	Renewable Portfolio Standards Compliance - CA		49,313			49,313
2	Deferred Intervenor Funding Grants - OR	1,069,569	373,389			1,442,958
3	Deferred Intervenor Funding Grants - CA	40,347	59			40,406
4	Deferred Intervenor Funding Grants - ID (2)	39,031	4,265	928	16,431	26,865
5	Alternative Rate for Energy (CARE) - CA		3,091			3,091
6	Deferred Overburden Cost - ID	254,022	1,495,704	501	1,446,390	303,336
7	Deferred Overburden Cost - WY	677,346	4,038,795	501	3,873,848	842,293
8	BPA Balancing Account - WA	316,957		440,442	316,957	
9	BPA Balancing Account - OR	1,468,531	470,930			1,939,461
10	Asset Sales Balancing Account - OR	142,389	105,082		247,471	
11	Property Insurance Reserve - OR		474,686			474,686
12	Property Insurance Reserve - WY	470,868	1,503	924	349,810	122,561
13	Misc. Regulatory Assets/Liabilities - OR	486,204	5,810		418,483	73,531
14	Utah Mine Disposition	86,357,715	117,148,464		17,173,630	186,332,549
15	Preferred Stock Redemption Loss - WY (10)	261,901		407.3	28,442	233,459
16	Preferred Stock Redemption Loss - UT (10)	759,970		407.3	82,531	677,439
17	Preferred Stock Redemption Loss - WA (10)		118,750	407.3	9,988	108,762
18	Merwin Fish Collector Project - WA (1)		529,312		366,726	162,586
19	Mobile Home Park Conversion - CA		1,729			1,729
20						
21						
22						
23						
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44	**TOTAL :**	1,589,995,081	404,698,012		315,623,265	1,679,069,828

Schedule Page: 232 Line No.: 6 Column: a
Weighted average remaining life is approximately one year for deferred excess net power cost mechanisms being amortized.

Schedule Page: 232 Line No.: 7 Column: a
Weighted average remaining life is approximately one year for deferred excess net power cost mechanisms being amortized, including Monsanto and Agrium net power cost components.

Schedule Page: 232 Line No.: 8 Column: a
Weighted average remaining life is approximately one year for deferred excess net power cost mechanisms being amortized.

Schedule Page: 232 Line No.: 9 Column: a
Weighted average remaining life is approximately one year for deferred excess net power cost mechanisms being amortized.

Schedule Page: 232 Line No.: 10 Column: a
Weighted average remaining life is approximately one year for deferred excess renewable energy credits in rates being amortized.

Schedule Page: 232 Line No.: 11 Column: a
Weighted average remaining life is approximately one year for deferred excess renewable energy credits and sulfur dioxide revenues in rates being amortized.

Schedule Page: 232 Line No.: 12 Column: a
Weighted average remaining life is approximately one year for deferred excess renewable energy credits in rates being amortized.

Schedule Page: 232 Line No.: 14 Column: a
Weighted average remaining life is 26 years. Amounts primarily represent income tax benefits and expense related to certain property-related basis differences and other various items that PacifiCorp is required to pass on to its customers.

Schedule Page: 232 Line No.: 18 Column: d
Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting

Schedule Page: 232 Line No.: 19 Column: a
Weighted average remaining life is eight years. Substantially represents amounts not yet recognized as a component of net periodic benefit cost that are expected to be included in rates when recognized.

Schedule Page: 232 Line No.: 19 Column: d
Pensions are associated with labor and generally charged to operations and maintenance expense and construction work in progress.

Schedule Page: 232 Line No.: 20 Column: a
Weighted average remaining life of portion being amortized is eight years. Substantially represents amounts not yet recognized as a component of net periodic benefit cost that are expected to be included in rates when recognized.

Schedule Page: 232 Line No.: 20 Column: d
Account 228.3, Accumulated provision for pensions and benefits
Account 426.5, Other deductions

Schedule Page: 232 Line No.: 21 Column: a
Weighted average remaining life is five years.

Schedule Page: 232 Line No.: 21 Column: d
Other postemployment costs are associated with labor and generally charged to operations and maintenance expense and construction work in progress. Also credited to Account 228.3, Accumulated provision for pensions and benefits.

Schedule Page: 232 Line No.: 29 Column: a
Weighted average remaining life is 27 years.

Schedule Page: 232 Line No.: 30 Column: a
Weighted average remaining life is 18 years.

Schedule Page: 232 Line No.: 31 Column: d

Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting

Schedule Page: 232 Line No.: 39 Column: a

Weighted average remaining life is eight years. Represents frozen values of contracts previously accounted for as derivatives and recorded at fair value.

Schedule Page: 232 Line No.: 40 Column: a

Weighted average remaining life is five years.

Schedule Page: 232 Line No.: 42 Column: d

Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting

Schedule Page: 232.1 Line No.: 10 Column: d

Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting

Schedule Page: 232.1 Line No.: 13 Column: d

Account 254, Other regulatory liabilities
Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting

Schedule Page: 232.1 Line No.: 14 Column: a

Weighted average remaining life of portion being amortized is approximately four years. Refer to Note 5 of Notes to Financial Statements in this Form No. 1.

Schedule Page: 232.1 Line No.: 14 Column: d

Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting
Account 501, Fuel

Schedule Page: 232.1 Line No.: 18 Column: d

Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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 $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Joseph Settlement (21)	423,590		557	137,381	286,209
2						
3	Lacomb Irrigation (24)	323,850		557	45,720	278,130
4						
5	Bogus Creek (41)	1,035,440		557	41,280	994,160
6						
7	Mead Phoenix Availability and					
8	Transmission Charge (50)	12,245,720		565	377,760	11,867,960
9						
10	TGS Buyout (23)	78,656		557	15,473	63,183
11						
12	Point-to-Point Transmission	1,054,377	501,803	142	143,308	1,412,872
13						
14	Hermiston Swap (40)	3,705,711		557	171,694	3,534,017
15						
16	Oregon Prepaid REC Purchases					
17	for RPS Compliance (1)	98,273	52,626	555	138,949	11,950
18						
19	Deferred Longwall Costs	26,832		501	26,832	
20						
21	Deferred Coal Costs - Wyodak					
22	Settlement (22)	2,681,454		151	335,182	2,346,272
23						
24	Deferred Coal Costs - Naughton					
25	Settlement (7)	2,752,307		151	1,376,153	1,376,154
26						
27	Deferred Coal Costs - Jim					
28	Bridger Plant	2,916,673		151	2,916,673	
29						
30	Deferred Colstrip Plant					
31	Costs (5)	325,000		501	300,000	25,000
32						
33	LT Lease Commissions					
34	Prepaids (10)	333,059		931	99,515	233,544
35						
36	LT Lease Commission - One Utah					
37	Center		66,739			66,739
38						
39	Lake Side Maintenance Prepaid	26,426,083	6,363,555	107	27,641,784	5,147,854
40						
41	Lake Side 2 Maintenance Prepaid	5,281,592	5,523,991			10,805,583
42						
43	Chehalis Maintenance Prepaid	21,838,914	3,161,822	107	22,144,147	2,856,589
44						
45	Currant Creek Maint. Prepaid	13,996,108	6,197,215			20,193,323
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	110,913,409				70,244,403

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Lease Incentives (10)	492,642		454	161,448	331,194
2						
3	Credit Agreement Costs (5)	2,141,252		427, 431	744,271	1,396,981
4						
5	PCRB LOC/SBBPA Costs	88,026	177,358	427	122,894	142,490
6						
7	PCRB Mode Conversion Costs	245,844	116,549	427	102,679	259,714
8						
9	'94 Series Restruct. Costs (16)	611,783		427	62,215	549,568
10						
11	Deferred S-3 Shelf Regis. Costs		186,399			186,399
12						
13	LT Prepaid IBEW 57 Pension					
14	Contribution	4,787,907	145,938		4,083,647	850,198
15						
16	BPA LT Transmission Prepaid	4,717,195	170,027	565	984,796	3,902,426
17						
18	Emission Reduction Credits	306,510				306,510
19						
20	Unamortized Contract Values	131,614		174	131,614	
21						
22	Sales of Electric Utility					
23	Facilities & Properties	1,845,747	869,163		2,003,907	711,003
24						
25	IT Licenses and Maint. Prepaid		240,580	921, 923	132,199	108,381
26						
27	Other Deferred Charges	1,250		181	1,250	
28						
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41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	110,913,409				70,244,403

Schedule Page: 233.1 Line No.: 5 Column: a

Weighted average life is two years.

Schedule Page: 233.1 Line No.: 7 Column: a

Weighted average life is nine years.

Schedule Page: 233.1 Line No.: 14 Column: d

Pensions are associated with labor and generally charged to operations and maintenance expense and construction work in progress.

Schedule Page: 233.1 Line No.: 23 Column: d

Account 102, Electric plant purchased or sold
Account 114, Electric plant acquisition adjustments
Account 539, Miscellaneous hydraulic power generation expenses
Account 592, Maintenance of station equipment
Account 593, Maintenance of overhead lines

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Employee benefits	182,825,392	189,756,726
3	Derivative contracts and unamortized contract values	79,219,960	93,561,265
4	State carryforwards	68,037,070	68,772,466
5	Loss contingencies	51,188,383	56,218,611
6	Asset retirement obligations	47,023,073	80,689,134
7	Other	116,675,654	117,213,002
8	TOTAL Electric (Enter Total of lines 2 thru 7)	544,969,532	606,211,204
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)	544,969,532	606,211,204

Notes

Schedule Page: 234 Line No.: 7 Column: a

Description and Location (a)	Bal. at Beg. of Year (b)	Bal. at End of Year (c)
Regulatory Liabilities	$ 28,575,535	$ 29,935,861
Other	88,100,119	87,277,141
	$116,675,654	$117,213,002

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common Stock (Account 201)	750,000,000		
2	Berkshire Hathaway Energy Company			
3	indirectly owns all of the shares of			
4	PacifiCorp's outstanding common stock.			
5	Therefore, there is no public market for			
6	PacifiCorp's common stock.			
7				
8	TOTAL COMMON STOCK	750,000,000		
9				
10				
11	Preferred Stock (Account 204):			
12	5% Cumulative Preferred	126,533	100.00	
13				
14	Serial Preferred, Cumulative:	3,500,000		
15	7.00% Series		100.00	
16	6.00% Series		100.00	
17	No Par Serial Preferred	16,000,000		
18	TOTAL PREFERRED STOCK	19,626,533		
19				
20	Authorized and Unissued Capital Stock			
21				
22				
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42				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		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
						6
						7
357,060,915	3,417,945,896					8
						9
						10
						11
						12
						13
						14
18,046	1,804,600					15
5,930	593,000					16
						17
23,976	2,397,600					18
						19
						20
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						42

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.: 20 Column: a

Authorizations for the issuance of common stock 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, 2015, PacifiCorp had regulatory approval from the aforementioned commissions for the issuance of an additional 30,000,000 shares of common stock out of the 750,000,000 authorized (357,060,915 outstanding) by PacifiCorp's articles of incorporation.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	14,422,979
5	Benefit plan separation	-3,575,760
6	Capital contributions	1,089,950,000
7	Gain on sale of ScottishPower plc stock	136,208
8	Qualified production activity tax deduction	-1,275,241
9	Contribution of Intermountain Geothermal	432,552
10		
11		
12		
13		
14		
15		
16		
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40	TOTAL	1,102,063,956

FOOTNOTE DATA

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

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

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

Represents the income tax deduction attributable to the exercise of stock options granted by ScottishPower plc.

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

Represents the effect of transferring certain benefit plan obligations and assets to PPM Energy, Inc. as a result of the sale of PacifiCorp by ScottishPower plc.

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

Represents capital contributions to PacifiCorp (with no shares of stock issued) from its indirect parent Berkshire Hathaway Energy Company ("BHE"). No capital contributions were made by BHE to PacifiCorp during the year ended December 31, 2015.

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, which invested in ScottishPower plc stock.

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

Represents amounts associated with Internal Revenue Code Section 199 qualified production activities.

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	41,101,061
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
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14		
15		
16		
17		
18		
19		
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21		
22	TOTAL	41,101,061

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	8.294% Series due October 1, 2015	46,946,000	
5	8.635% Series due October 1, 2016	18,750,000	
6	8.470% Series due October 1, 2017	19,609,000	
7	5.65% Series due July 15, 2018	500,000,000	3,067,221
8			905,000 D
9	5.50% Series due January 15, 2019	350,000,000	2,515,793
10			2,292,500 D
11	3.85% Series due June 15, 2021	400,000,000	3,007,139
12			744,000 D
13	2.95% Series due February 1, 2022	350,000,000	2,424,350
14			308,000 D
15	2.95% Series due February 1, 2022	100,000,000	254,129
16			-81,000 P
17	2.95% Series due June 1, 2023	300,000,000	1,859,352
18			900,000 D
19	3.60% Series due April 1, 2024	425,000,000	3,345,164
20			255,000 D
21	3.35% Series due July 1, 2025	250,000,000	2,121,421
22			320,000 D
23	7.70% Series due November 15, 2031	300,000,000	2,874,150
24			864,000 D
25	5.90% Series due August 15, 2034	200,000,000	1,892,365
26			722,000 D
27	5.25% Series due June 15, 2035	300,000,000	2,912,021
28			1,080,000 D
29	6.10% Series due August 1, 2036	350,000,000	2,907,881
30			1,141,000 D
31	5.75% Series due April 1, 2037	600,000,000	589,216
32			24,000 D
33	TOTAL	7,354,645,000	78,372,455

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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.
						1
						2
						3
04/15/1992	10/01/2015	04/15/1992	10/01/2015		259,892	4
04/15/1992	10/01/2016	04/15/1992	10/01/2016	1,686,000	246,292	5
04/15/1992	10/01/2017	04/15/1992	10/01/2017	3,313,000	373,739	6
07/17/2008	07/15/2018	07/17/2008	07/15/2018	500,000,000	28,250,000	7
						8
01/08/2009	01/15/2019	01/08/2009	01/15/2019	350,000,000	19,250,000	9
						10
05/12/2011	06/15/2021	05/12/2011	06/15/2021	400,000,000	15,400,000	11
						12
01/06/2012	02/01/2022	01/06/2012	02/01/2022	350,000,000	10,325,000	13
						14
03/06/2012	02/01/2022	03/06/2012	02/01/2022	100,000,000	2,950,000	15
						16
06/06/2013	06/01/2023	06/06/2013	06/01/2023	300,000,000	8,850,000	17
						18
03/13/2014	04/01/2024	03/13/2014	04/01/2024	425,000,000	15,300,000	19
						20
06/19/2015	07/01/2025	06/19/2015	07/01/2025	250,000,000	4,466,667	21
						22
11/21/2001	11/15/2031	11/21/2001	11/15/2031	300,000,000	23,100,000	23
						24
08/24/2004	08/15/2034	08/24/2004	08/15/2034	200,000,000	11,800,000	25
						26
06/13/2005	06/15/2035	06/13/2005	06/15/2035	300,000,000	15,750,000	27
						28
08/10/2006	08/01/2036	08/10/2006	08/01/2036	350,000,000	21,350,000	29
						30
03/14/2007	04/01/2037	03/14/2007	04/01/2037	600,000,000	34,500,000	31
						32
				7,159,339,000	356,471,778	33

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	2,290,333
4			1,671,000 D
5	6.00% Series due January 15, 2039	650,000,000	6,134,687
6			6,175,000 D
7	4.10% Series due February 1, 2042	300,000,000	2,737,911
8			987,000 D
9	8.53% Series C Medium-Term Notes due Dec. 16, 2021	15,000,000	115,202
10	8.375% Series C Medium-Term Notes due Dec. 31, 2021	5,000,000	38,400
11	8.26% Series C Medium-Term Notes due Jan. 7, 2022	5,000,000	33,243
12	8.27% Series C Medium-Term Notes due Jan. 10, 2022	4,000,000	30,594
13	8.05% Series E Medium-Term Notes due Sept. 1, 2022	15,000,000	131,471
14	8.07% Series E Medium-Term Notes due Sept. 9, 2022	8,000,000	70,118
15	8.12% Series E Medium-Term Notes due Sept. 9, 2022	50,000,000	438,238
16	8.11% Series E Medium-Term Notes due Sept. 9, 2022	12,000,000	105,177
17	8.05% Series E Medium-Term Notes due Sept. 14, 2022	10,000,000	87,648
18	8.08% Series E Medium-Term Notes due Oct. 14, 2022	26,000,000	208,198
19	8.08% Series E Medium-Term Notes due Oct. 14, 2022	25,000,000	200,190
20	8.23% Series E Medium-Term Notes due Jan. 20, 2023	5,000,000	37,914
21	8.23% Series E Medium-Term Notes due Jan. 20, 2023	4,000,000	30,331
22			-81,560 P
23	7.26% Series F Medium-Term Notes due July 21, 2023	27,000,000	246,981
24	7.26% Series F Medium-Term Notes due July 21, 2023	11,000,000	100,622
25	7.23% Series F Medium-Term Notes due Aug. 16, 2023	15,000,000	137,211
26	7.24% Series F Medium-Term Notes due Aug. 16, 2023	30,000,000	274,423
27	6.75% Series F Medium-Term Notes due Sept. 14, 2023	5,000,000	38,250
28	6.75% Series F Medium-Term Notes due Sept. 14, 2023	2,000,000	15,300
29	6.72% Series F Medium-Term Notes due Sept. 14, 2023	2,000,000	15,300
30	6.75% Series F Medium-Term Notes due Oct. 26, 2023	20,000,000	152,326
31	6.75% Series F Medium-Term Notes due Oct. 26, 2023	16,000,000	121,861
32	6.75% Series F Medium-Term Notes due Oct. 26, 2023	12,000,000	91,396
33	TOTAL	7,354,645,000	78,372,455

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	19,050,000	3
						4
01/08/2009	01/15/2039	01/08/2009	01/15/2039	650,000,000	39,000,000	5
						6
01/06/2012	02/01/2042	01/06/2012	02/01/2042	300,000,000	12,300,000	7
						8
12/16/1991	12/16/2021	12/16/1991	12/16/2021	15,000,000	1,279,500	9
12/31/1991	12/31/2021	12/31/1991	12/31/2021	5,000,000	418,750	10
01/08/1992	01/07/2022	01/08/1992	01/07/2022	5,000,000	413,000	11
01/09/1992	01/10/2022	01/09/1992	01/10/2022	4,000,000	330,800	12
09/18/1992	09/01/2022	09/18/1992	09/01/2022	15,000,000	1,207,500	13
09/09/1992	09/09/2022	09/09/1992	09/09/2022	8,000,000	645,600	14
09/11/1992	09/09/2022	09/11/1992	09/09/2022	50,000,000	4,060,000	15
09/11/1992	09/09/2022	09/11/1992	09/09/2022	12,000,000	973,200	16
09/14/1992	09/14/2022	09/14/1992	09/14/2022	10,000,000	805,000	17
10/15/1992	10/14/2022	10/15/1992	10/14/2022	26,000,000	2,100,800	18
10/15/1992	10/14/2022	10/15/1992	10/14/2022	25,000,000	2,020,000	19
01/20/1993	01/20/2023	01/20/1993	01/20/2023	5,000,000	411,500	20
01/29/1993	01/20/2023	01/29/1993	01/20/2023	4,000,000	329,200	21
						22
07/22/1993	07/21/2023	07/22/1993	07/21/2023	27,000,000	1,960,200	23
07/22/1993	07/21/2023	07/22/1993	07/21/2023	11,000,000	798,600	24
08/16/1993	08/16/2023	08/16/1993	08/16/2023	15,000,000	1,084,500	25
08/16/1993	08/16/2023	08/16/1993	08/16/2023	30,000,000	2,172,000	26
09/14/1993	09/14/2023	09/14/1993	09/14/2023	5,000,000	337,500	27
09/14/1993	09/14/2023	09/14/1993	09/14/2023	2,000,000	135,000	28
09/14/1993	09/14/2023	09/14/1993	09/14/2023	2,000,000	134,400	29
10/26/1993	10/26/2023	10/26/1993	10/26/2023	20,000,000	1,350,000	30
10/26/1993	10/26/2023	10/26/1993	10/26/2023	16,000,000	1,080,000	31
10/26/1993	10/26/2023	10/26/1993	10/26/2023	12,000,000	810,000	32
				7,159,339,000	356,471,778	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	6.71% Series G Medium-Term Notes due Jan. 15, 2026	100,000,000	904,467
2	Subtotal - First Mortgage Bonds	6,784,305,000	68,661,215
3			
4	Pollution Control Obligations - Secured by Pledged First Mortgage Bonds:		
5			
6	Poll Ctrl Rev Refunding Bonds, Sweetwater County, WY, Series 1994	21,260,000	510,479
7	Poll Ctrl Rev Refunding Bonds, Converse County, WY, Series 1994	8,190,000	209,777
8	Poll Ctrl Rev Refunding Bonds, Emery County, UT, Series 1994	121,940,000	3,274,246
9	Poll Ctrl Rev Refunding Bonds, Carbon County, UT, Series 1994	9,365,000	206,519
10	Poll Ctrl Rev Refunding Bonds, Lincoln County, WY, Series 1994	15,060,000	422,858
11	Poll Ctrl Rev Refunding Bonds, Lincoln Cnty, WY, Series 1991	45,000,000	771,836
12	Poll Ctrl Revenue Bonds, City of Forsyth, MT, Series 1986	8,500,000	304,824
13	Environ. Imprvmnt Rev Bonds, Converse County, WY, Series 1995	5,300,000	132,043
14	Environ. Imprvmnt Rev Bonds, Lincoln County, WY, Series 1995	22,000,000	404,262
15	Subtotal Pollution Control Obligations - Secured by Pledged First Mortgage Bonds	256,615,000	6,236,844
16			
17			
18	Pollution Control Obligations - Unsecured:		
19			
20	Poll Ctrl Rev Refndng Bonds, Emery County, UT, Series 1991	45,000,000	872,505
21	Poll Ctrl Rev Refndng Bonds, City of Forsyth, MT, Series 1988	45,000,000	380,198
22	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Series 1988A	50,000,000	422,443
23	Poll Ctrl Rev Refndng Bonds, City of Gillette, WY, Ser. 1988	41,200,000	351,905
24	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1990A	70,000,000	660,750
25	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1992A	9,335,000	167,524
26	Poll Ctrl Rev Refndng Bonds, Converse County, WY, Series 1992	22,485,000	242,163
27	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1992B	6,305,000	151,908
28	Environ. Imprvmnt Rev Bonds, Sweetwater County, WY, Series 1995	24,400,000	225,000
29	Subtotal - Pollution Control Obligations - Unsecured	313,725,000	3,474,396
30			
31			
32	TOTAL ACCOUNT 221	7,354,645,000	78,372,455
33	TOTAL	7,354,645,000	78,372,455

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.
01/23/1996	01/15/2026	01/23/1996	01/15/2026	100,000,000	6,710,000	1
				6,703,999,000	351,588,640	2
						3
						4
						5
11/17/1994	11/01/2024	11/17/1994	11/01/2024	21,260,000	248,042	6
11/17/1994	11/01/2024	11/17/1994	11/01/2024	8,190,000	68,014	7
11/17/1994	11/01/2024	11/17/1994	11/01/2024	121,940,000	1,289,589	8
11/17/1994	11/01/2024	11/17/1994	02/18/2016	9,365,000	152,866	9
11/17/1994	11/01/2024	11/17/1994	11/01/2024	15,060,000	141,623	10
01/17/1991	01/01/2016	01/17/1991	01/01/2016	45,000,000	499,433	11
12/01/1986	12/01/2016	12/01/1986	12/01/2016	8,500,000	53,162	12
11/17/1995	11/01/2025	11/17/1995	11/01/2025	5,300,000	31,174	13
11/17/1995	11/01/2025	11/17/1995	11/01/2025	22,000,000	138,011	14
				256,615,000	2,621,914	15
						16
						17
						18
						19
05/23/1991	07/01/2015	05/23/1991	07/01/2015		383,702	20
01/01/1988	01/01/2018	01/01/1988	01/01/2018	45,000,000	490,892	21
01/01/1988	01/01/2017	01/01/1988	01/01/2017	50,000,000	294,002	22
01/01/1988	01/01/2018	01/01/1988	01/01/2018	41,200,000	233,576	23
07/25/1990	07/01/2015	07/25/1990	07/01/2015		317,483	24
09/29/1992	12/01/2020	09/29/1992	12/01/2020	9,335,000	80,866	25
09/29/1992	12/01/2020	09/29/1992	12/01/2020	22,485,000	189,709	26
09/29/1992	12/01/2020	09/29/1992	12/01/2020	6,305,000	55,786	27
12/14/1995	11/01/2025	12/14/1995	11/01/2025	24,400,000	215,208	28
				198,725,000	2,261,224	29
						30
						31
				7,159,339,000	356,471,778	32
				7,159,339,000	356,471,778	33

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			
2	Reacquired Bonds: (Account 222)		
3			
4	Advances from Associated Companies: (Account 223)		
5			
6	Other Long-Term Debt: (Account 224)		
7			
8			
9	Long-Term Debt Authorized but Unissued		
10			
11			
12			
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14			
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20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	7,354,645,000	78,372,455

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
						4
						5
						6
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						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				7,159,339,000	356,471,778	33

Schedule Page: 256 Line No.: 21 Column: a

In June 2015, PacifiCorp issued $250 million of its 3.35% First Mortgage Bonds due July 2025. State commission authorizations for this issuance were as follows:

- Oregon Public Utility Commission ("OPUC") - Docket No. UF-4288, Order No. 14-268, dated July 22, 2014.
- Idaho Public Utilities Commission ("IPUC") - Case No. PAC-E-14-05, Order No. 33083, dated July 29, 2014.

Schedule Page: 256.2 Line No.: 9 Column: e

In February 2016, PacifiCorp redeemed the Pollution Control Revenue Refunding Bonds, Carbon County, UT, Series 1994 and transferred the associated unamortized debt expense to Account 189, Unamortized loss on reacquired debt.

Schedule Page: 256.2 Line No.: 32 Column: h

Refer to Item 6 in Important Changes During the Year and Note 7 in Notes to Financial Statements in this Form No. 1 for a discussion of PacifiCorp's long-term debt.

Schedule Page: 256.2 Line No.: 32 Column: i

Amount represents interest expense charged to Account 427, Interest on long-term debt, and does not include any amount charged to Account 430, Interest on debt to associated companies, as all such interest was accrued on amounts included in Account 233, Notes payable to associated companies.

Schedule Page: 256.3 Line No.: 9 Column: a

As of January 2016, PacifiCorp had an effective shelf registration statement filed with the Unites States Securities and Exchange Commission on Form S-3 to issue up to $1.325 billion of future first mortgage bonds through January 2019.

For authorization for the issuance of long-term debt ($1.575 billion authorized; $1.325 billion available as of December 31, 2015), refer to Item 6 in Important Changes During the Year in 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, 2015) by the counties of Emery, Utah; Carbon, Utah; Converse, Wyoming; Lincoln, Wyoming; Sweetwater, Wyoming; and Moffat, Colorado and authorization to borrow the proceeds of new pollution control revenue bonds issued (total of $150,000,000 authorized and available as of December 31, 2015) 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:

- OPUC - Docket No. UF-4250, Order No. 08-382, dated July 29, 2008.
- IPUC - Case No. PAC-E-08-05, Order No. 30606, dated August 4, 2008.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	695,335,538
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8	Other	141,770,817
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13	Other	1,393,392,991
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18	Other	37,044,036
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25	Other	1,644,070,546
26	State Tax Deductions	-23,936,240
27	Federal Tax Net Income	525,448,524
28	Show Computation of Tax:	
29		
30	Federal Income Tax at 35.00%	183,906,983
31	Provision to Return Adjustment	-2,001,391
32	Tax Reserve Changes	2,595,330
33	Renewable Energy Production Tax Credits	-59,173,010
34	Other Federal Tax Credits	-5,937
35		
36	Federal Income Tax Accrual	125,321,975
37		
38		
39		
40		
41		
42		
43		
44		

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

Particulars (Details)	Amounts
Contribution in Aid of Construction	108,326,668
Deferred Revenue - Lease Incentives	627,367
Federal Tax Fixed Asset Gain/Loss	9,602,156
Regulatory Asset - BPA Balancing Account - WA	316,957
Regulatory Asset - REC Sales Deferral - UT - Current	7,199,293
Regulatory Asset - REC Sales Deferral - UT - Noncurrent	448,228
Regulatory Asset - REC Sales Deferral - WA - Current	1,843,964
Regulatory Asset - REC Sales Deferral - WY - Current	2,198,465
Regulatory Asset - WA Colstrip #3	52,188
Reimbursements	1,386,597
Regulatory Liability - BPA Balancing Account - ID	1,328,270
Regulatory Liability - BPA Balancing Account - WA	54,637
Regulatory Liability - Deferred Excess NPC - OR - Noncurrent	5,772,211
Regulatory Liability - Deferred Excess NPC - WA - Noncurrent	132,174
Regulatory Liability - Depreciation Decrease - OR	999,943
Regulatory Liability - GHG Allowance Revenues - CA - Noncurrent	718,381
Regulatory Liability - OR 2012 GRC Giveback - Noncurrent	418,227
Regulatory Liability - Sale of REC - OR - Noncurrent	33,376
Regulatory Liability - WA Low Energy Program	311,715
Total	$ 141,770,817

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

Particulars (Details)	Amounts
Fed/State Tax Expense	320,634,528
Fed/State Tax Expense - Interest	881,589
50% Meals and Entertainment	766,181
Accrued Royalties	1,685,119
Accrued Severance	103,470
Avoided Costs	23,148,802
Bear River Settlement Agreement	176,138
Book Depreciation	768,720,000
Book Depreciation Allocated to Medicare and M&E	76,634
Coal Pile Inventory Adjustment	6,766,483
Contra Receivable from Joint Owners	5,049,536
CWIP Reserve	422,245
Deferred Compensation - Mark to Market Gain/Loss - Income Statement	728,412
Deferred Coal Costs - Naughton Contract Settlement	1,376,154
Deferred Revenue - Other	95,833
Energy West Accrued Liabilities	645,912
Environmental Liability - Non-Regulated	5,577
Environmental Liability - Regulated	1,508,186
Fuel Cost Adjustment	14,014
Hermiston Swap	171,693
Hydro Relicensing Obligation	1,343,975
Insurance Reserve - Current	22,855,900
Inventory Reserve	952,973
Joseph Settlement	137,381
Lewis River Settlement Agreement	53,365
Lobbying Expenses	2,580,424
LT Incentive Plan - Noncurrent	1,549,445
LT Incentive Plan - Mark to Market Gain/Loss - Income Statement	78,855
Medicare Subsidy	8,060,641
MEHC Insurance Services - Receivable	29,933
Mine Rescue Training Credit Addback	5,937
Miscellaneous Current and Accrued Liability	887,932
Penalties	1,380,071

Prepaid Aircraft Maintenance	10,622
Prepaid IBEW 57 Pension Contribution - Current	4,200,000
Prepaid Taxes - Property Taxes	231,066
Regulatory Asset - Asset Sales Balancing Account	142,389
Regulatory Asset - Chehalis Generating Facility Deferral - WA	3,000,000
Regulatory Asset - Cholla Plant Transaction Costs	1,122,425
Regulatory Asset - Deferred Excess NPC - CA - Current	3,404,629
Regulatory Asset - Deferred Excess NPC - ID - Current	19,801,431
Regulatory Asset - Deferred Excess NPC - UT - Current	42,492,609
Regulatory Asset - Deferred Excess NPC - WY - Current	21,672,534
Regulatory Asset - Deferred Intervenor Funding Grants - ID	12,165
Regulatory Asset - DSM - Current	21,403,890
Regulatory Asset - DSM - Noncurrent	1,211,413
Regulatory Asset - Depreciation Increase - UT	128,043
Regulatory Asset - Depreciation Increase - WY	442,191
Regulatory Asset - Environmental Costs - WA	206,865
Regulatory Asset - FAS 158 Pension Liability	41,324,556
Regulatory Asset - GHG Allowances - CA - Current	5,110,660
Regulatory Asset - Goodnoe Hills Settlement - WY	21,250
Regulatory Asset - Klamath Hydroelectric Relicensing Costs - UT	3,000,146
Regulatory Asset - Lake Side Settlement - WY	27,331
Regulatory Asset - Liquidation Damages - Naughton Unit #2 - WY	5,708
Regulatory Asset - Naughton Unit #3 Costs - CA	51,021
Regulatory Asset - Naughton Unit #3 Costs - ID	239,495
Regulatory Asset - OR Sch 203 Black Cap Solar	11,572
Regulatory Asset - Pension MMT - UT	283,176
Regulatory Asset - Post Employment Costs	4,944,224
Regulatory Asset - Post Merger Loss - Reacquired Debt	832,212
Regulatory Asset - Postretirement MMT - CA	17,488
Regulatory Asset - Postretirement MMT - OR	193,035
Regulatory Asset - Postretirement MMT - UT	278,648
Regulatory Asset - Powerdale Decommissioning - ID	26,216
Regulatory Asset - Preferred Stock Redemption Loss - WY	28,442
Regulatory Asset - Preferred Stock Redemption Loss - UT	82,531
Regulatory Asset - Solar Feed-in Tariff Deferral - OR - Current	4,122,390
Regulatory Asset - Tax Revenue Requirement Adj - WY	17,633
Regulatory Asset - UT Liquidation Damages	35,000
Regulatory Asset - Postretirement Settlement Loss	1,110,082
Regulatory Liability - 50% Bonus Tax Depreciation - WY	968,851
Regulatory Liability - ARO/Reg Diff - Trojan - WA Portion	8,336
Regulatory Liability - Blue Sky - CA	46,963
Regulatory Liability - Blue Sky - ID	33,755
Regulatory Liability - Blue Sky - OR	173,491
Regulatory Liability - Blue Sky - UT	1,426,381
Regulatory Liability - Blue Sky - WY	132,802
Regulatory Liability - Injuries & Damages Reserve - OR	3,134,945
Regulatory Liability - Property Insurance Reserve - ID	112,950
Regulatory Liability - Property Insurance Reserve - UT	814,186
Regulatory Liability - Property Insurance Reserve - WY	348,307
Regulatory Liability - Solar Feed-in Tariff Deferral - CA - Noncurrent	1,530,061
Regulatory Liability - Solar Incentive Program - UT - Noncurrent	13,835,120
Sales and Use Tax Audit Exposure	250,977
TGS Buyout	15,474
Trapper Mine Contract Obligation	5,723,944
USA Power Litigation	2,480,165
Utah Mine Disposition	7,931,642
Intercompany adjustment	286,215
Total	$ 1,393,392,991

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

Particulars (Details)	Amounts
Book Fixed Asset Gain/Loss	(10,995,672)
Dividend Received Deduction - Deferred Compensation	(168,574)
Foote Creek Contract	(17,100)
MCI F.O.G. Wire Lease	(196)
Officer's Life Insurance	(4,233,074)
Redding Contract	(550,096)
Regulatory Asset - Alt Rate for Energy Program (CARE) - CA - Current	(3,091)
Regulatory Asset - BPA Balancing Account - OR	(470,930)
Regulatory Asset - REC Sales Deferral - WA - Noncurrent	(96,604)
Regulatory Asset - REC Sales Deferral - WY - Noncurrent	(604,911)
Regulatory Liability - Alt Rate for Energy Program (CARE) - CA - Current	(674,990)
Regulatory Liability - Depreciation Decrease - WA	(400,163)
Regulatory Liability - GHG Allowance Revenues - CA - Current	(2,904,622)
Regulatory Liability - Sale of REC - OR - Current	(404,974)
Regulatory Liability - UT Home Energy Lifeline	(1,231,747)
Transmission Service Deposit	(119,705)
Trapper Mining Stock Basis	(571,734)
Unearned Joint Use Pole Contact Revenue	(50,904)
Equity Earnings in Subsidiaries	(13,544,949)
Total	$ (37,044,036)

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

Particulars (Details)	Amounts
Accrued Bonus	(162,237)
Accrued Final Reclamation	(4,730,005)
Accrued Vacation	(2,245,437)
Amortization NOPAs 99-00 RAR	(50,796)
Basis Intangible Difference	(219,947)
Capitalized Depreciation	(4,977,004)
Capitalized Labor and Benefit Costs	(809,045)
Cholla SHL NOPA (Lease Amortization)	(191,965)
Cost of Removal	(56,702,091)
Debt AFUDC	(17,514,314)
Deferred Compensation - Noncurrent	(50,737)
Deferred Revenue - Citibank	(154,403)
Deseret Settlement Receivable	(109,670)
Equity AFUDC - Temp	(32,697,891)
FAS 112 Book Reserve - Postemployment Benefits	(2,430,201)
FAS 158 Pension Liability	(21,986,127)
FAS 158 Postretirement Liability	(5,148,750)
FAS 158 SERP Liability	(1,018,300)
Federal Tax Depreciation	(1,137,695,628)
Injuries and Damages Accrual - Cash Basis	(12,081,532)
LT Prepaid IBEW 57 Pension Contribution	(262,290)
N Umpqua Settlement Agreement	(284,997)
Non-deductible Postretirement Costs	(8,060,641)
Oregon Regulatory Asset/Regulatory Liability Consolidation	(17,126)
Other Environmental Liabilities	(189,999)
Pension/Retirement Accrual	(131,928)
Pre-1943 Preferred Stock Dividend - Deduction	(64,760)
Prepaid Membership Fees	(1,399,654)
Prepaid Taxes - IPUC	(3,604)
Prepaid Taxes - OPUC	(14,235)
Prepaid Taxes - UPSC	(52,014)
Prepaid Water Rights	(154,287)
Qualified Production Activities Deduction	(15,808,349)
Regulatory Asset - CA Mobile Home Park Conversion	(1,728)

Regulatory Asset - Carbon Unrecovered Plant - ID	(286,822)
Regulatory Asset - Carbon Unrecovered Plant - UT	(2,623,990)
Regulatory Asset - Carbon Unrecovered Plant - WY	(461,260)
Regulatory Asset - Cholla Plant Transaction Costs - ID	(32,973)
Regulatory Asset - Cholla Plant Transaction Costs - OR	(53,813)
Regulatory Asset - Cholla Plant Transaction Costs - WA	(97,006)
Regulatory Asset - Contra Pension MMT & CTG - CA	(91,920)
Regulatory Asset - Contra Pension MMT & CTG - OR	(1,014,634)
Regulatory Asset - Deferred Excess NPC - CA - Noncurrent	(2,705,726)
Regulatory Asset - Deferred Excess NPC - ID - Noncurrent	(16,592,103)
Regulatory Asset - Deferred Excess NPC - UT - Noncurrent	(19,836,501)
Regulatory Asset - Deferred Excess NPC - WY '09 & After - Noncurrent	(11,929,181)
Regulatory Asset - Deferred Independent Evaluator Fee - UT	(62,152)
Regulatory Asset - Deferred Intervenor Funding Grants - CA	(59)
Regulatory Asset - Deferred Intervenor Funding Grants - OR	(373,388)
Regulatory Asset - Deferred Overburden Costs - ID	(49,314)
Regulatory Asset - Deferred Overburden Costs - WY	(164,947)
Regulatory Asset - Depreciation Increase - ID	(1,669,470)
Regulatory Asset - DSM Balance Reclass	(19,513,285)
Regulatory Asset - Environmental Costs	(4,624,874)
Regulatory Asset - FAS 158 Postretirement Liability	(5,177,908)
Regulatory Asset - GHG Allowances - CA - Noncurrent	(796,626)
Regulatory Asset - Merwin Fish Collector Project - WA	(162,586)
Regulatory Asset - OR Sch 94 Distribution Safety Surcharge	(368,684)
Regulatory Asset - Preferred Stock Redemption Loss - WA	(108,761)
Regulatory Asset - REC Sales Deferral - CA	(49,313)
Regulatory Asset - Solar Feed-in Tariff Deferral - OR - Noncurrent	(4,437,377)
Regulatory Asset - UT Subscriber Solar Program	(21,683)
Regulatory Asset - Postretirement Settlement Loss CC - UT	(217,007)
Regulatory Asset - Postretirement Settlement Loss CC - WY	(88,977)
Regulatory Liability - Blue Sky - WA	(139,550)
Regulatory Liability - Contra-Carbon Decommissioning - ID	(281,047)
Regulatory Liability - Contra-Carbon Decommissioning - UT	(2,281,573)
Regulatory Liability - Contra-Carbon Decommissioning - WY	(215,893)
Regulatory Liability - Deferred Excess NPC - WA - Current	(121,961)
Regulatory Liability - DSM - Current	(1,890,608)
Regulatory Liability - OR Energy Conservation Charge	(288,091)
Regulatory Liability - Property Insurance Reserve - OR	(1,511,139)
Regulatory Liability - Solar Feed-in Tariff Deferral - CA - Current	(945,656)
Regulatory Liability - Solar Incentive Program - UT - Current	(10,116,877)
Regulatory Liability - Trojan Decommissioning	(36,847)
Repairs Deduction	(204,180,288)
Reserve for Bad Debts	(95,341)
Rogue River - Habitat Enhancement Liability	(25,104)
Tax Depletion - SRC	(126,598)
Wasatch Workers Comp Reserve	(153,941)
Western Coal Carrier Retiree Medical Accrual	(626,000)
Total	$ (1,644,070,546)

Schedule Page: 261 Line No.: 36 Column: b

Berkshire Hathaway Inc. includes PacifiCorp in its United States Federal Income Tax Return. PacifiCorp's provision for income taxes has been computed on a stand-alone basis.

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

Under Berkshire Hathaway Energy Company ("BHE"):
PPW Holdings LLC Sub-Group:
PacifiCorp
PPW Holdings LLC

PacifiCorp Sub-Group:

Energy West Mining Company
Glenrock Coal Company
Interwest Mining Company
Pacific Minerals, Inc.

BHE Sub-Group:
ABA Holding, LLC
ABA Management, L.L.C.
Alaska Gas Transmission Company, LLC
Allie Beth Allman Real Estate, Ltd
Arizona HomeServices, LLC
Berkshire Hathaway Energy Company
BG Energy Holding Company LLC
BHE AC Holding, LLC
BHE America Transco, LLC
BHE California Utility Holdco, LLC
BHE Canada LLC
BHE Geothermal, LLC
BHE Hydro, LLC
BHE Midcontinent Transmission Holdings LLC
BHE Renewables, LLC
BHE Solar, LLC
BHE Southwest Transmission Holdings LLC
BHE Texas Transco, LLC
BHE U.K. Electric, Inc.
BHE U.K. Inc.
BHE U.K. Power, Inc.
BHE U.S. Transmission, LLC
BHE Wind, LLC
BHH Affiliates, LLC
BHH KC Real Estate, LLC
Big Spring Pipeline Company
Bishop Hill Energy II, LLC
Bishop Hill II Holdings, LLC
BRER Affiliates, LLC
BRER Real Estate Services, LLC
BRER Realty Holding Company, LLC
BRER Referral Services, LLC
CalEnergy Company, Inc.
CalEnergy Generation Operating Company
CalEnergy Holdings, Inc.
CalEnergy International Services, Inc.
CalEnergy International, Inc.
CalEnergy Minerals Development, LLC
CalEnergy Minerals LLC
CalEnergy Operating Corporation
CalEnergy Pacific Holdings Corp
California Energy Development Corporation
California Energy Management Company
California Energy Yuma Corporation
Capitol Title Company
CBSHome Commercial, LLC
CBSHome Real Estate Company
CBSHome Real Estate of Iowa, Inc.
CBSHome Relocation Services, Inc.
CE Administrative Services, Inc.
CE Black Rock Holdings LLC
CE Butte Energy Holdings LLC
CE Butte Energy LLC
CE Electric (NY), Inc.
CE Gen Oil Company
CE Gen Pipeline Corporation
CE Gen Power Corporation
CE Generation LLC
CE Geothermal, Inc.
CE International Investments, Inc.
CE Leathers Company
CE Obsidian Energy LLC
CE Obsidian Holding LLC
CE Red Island Energy Holdings LLC
CE Red Island Energy LLC
CE Salton Sea Inc.

CE Texas Energy, LLC
CE Texas Fuel LLC
CE Texas Pipeline LLC
CE Texas Power LLC
CE Texas Resources LLC
CE Turbo LLC
Champion Realty, Inc.
Chancellor Title Services, Inc.
Cimmred Leasing Company
Columbia Title of Florida, Inc.
Commonsite, Inc.
Conejo Energy Company
Connecticut Referral Group, L.L.C.
Cordova Energy Company, LLC
Cordova Funding Corporation
CTHM, L.L.C.
CTRE, L.L.C.
Dakota Dunes Development Company
DCCO, Inc.
Desert Valley Company
DG-SB Project Holdings, LLC
Edina Financial Services, Inc.
Edina Realty Referral Network, Inc.
Edina Realty Relocation, Inc.
Edina Realty Title, Inc.
Edina Realty, Inc.
Elmore Company
eRealty, LLC
Esslinger-Wooten-Maxwell, Inc.
E-W-M Referral Services, Inc.
F&R/T LLC
Falcon Power Operating Company
FFR, Inc.
First Realty Group, Inc.
First Realty, Ltd
First Reserve Insurance, Inc.
First Weber Illinois, LLC
First Weber, Inc.
For Rent, Inc.
FRTC, LLC
FSRI Holdings, Inc.
Geronimo Community Solar Gardens, LLC
GPSF-B
Grande Prairie Wind, LLC
Guarantee Appraisal Corporation
Guarantee Real Estate
HMSV Financial Services, Inc.
HN Real Estate Group N.C., Inc.
HN Real Estate Group, LLC
HN Referral Corporation
HomeServices Financial Holdings, Inc.
HomeServices Insurance, Inc.
HomeServices Lending, LLC
HomeServices Northeast, LLC
HomeServices of Alabama, Inc.
HomeServices of America, Inc.
HomeServices of California, Inc.
HomeServices of Connecticut, LLC
HomeServices of Florida, Inc.
HomeServices of Georgia, LLC
HomeServices of Illinois Holdings, LLC
HomeServices of Iowa, Inc.
HomeServices of Kentucky, Inc.
HomeServices of MOKAN, LLC
HomeServices of Nebraska, Inc.
HomeServices of Oregon, LLC
HomeServices of Texas, LLC
HomeServices of the Carolinas, Inc.
HomeServices of Washington, LLC
HomeServices of Wisconsin, LLC
HomeServices Referral Network, LLC
HomeServices Relocation, LLC

HomeSvc of IL LLC d/b/a Koenig & Strey GMAC RE
HS Franchise Holding, LLC
HSGA Real Estate Group, L.L.C.
HSR Equity Funding, Inc.
HSW Affiliates Holding, LLC
Huff Commercial Group, LLC
Huff-Drees Realty, Inc.
IES Holding II LLC
IES Holding LLC
IMO Company, Inc.
Imperial Magma LLC
InsuranceSouth, LLC
Intelligent Energy Solutions LLC
Intero Franchise Services, Inc.
Intero Real Estate Holdings, Inc.
Intero Real Estate Services, Inc.
Intero Referral Services, Inc.
Iowa Realty Company, Inc.
Iowa Realty Insurance Agency, Inc.
Iowa Title Company
J.S. White Associates, Inc.
JBRC, Inc.
Jim Huff Realty, Inc.
JRHBW Realty, Inc. d/b/a RealtySouth
Jumbo Road Holdings, LLC
Kansas City Title, Inc.
Kentucky Residential Referral, LLC
Kern River Funding Corporation
KR Acquisition 1, LLC
KR Acquisition 2, LLC
KR Holding, LLC
Lands of Sierra, Inc.
Larabee School of Real Estate & Insurance, Inc.
M & M Ranch Acquisition Company LLC
M & M Ranch Holding Company LLC
Magma Land Company I
Magma Power Company
Marshall Wind Energy, LLC
MEC Construction Services Company
MEHC Insurance Services Ltd.
MEHC Investment, Inc.
MEHC Merger Sub Inc.
MHC Investment Company
MHC, Inc.
Mid-America Referral Network, Inc.
MidAmerican Central California Transco LLC
MidAmerican Energy Company
MidAmerican Energy Machining Services LLC
MidAmerican Funding, LLC
MidAmerican Nuclear Energy Company LLC
MidAmerican Wind Tax Equity Holdings, LLC
Midland Escrow Services, Inc.
Midwest Capital Group, Inc.
Midwest Power Transmission Arkansas LLC
Midwest Power Transmission Iowa LLC
Midwest Realty Ventures, LLC
MTL Canyon Holdings LLC
MWR Capital, Inc.
Nebraska Land Title & Abstract Company
Nebraska Referral, Inc.
Nevada Electric Investment Company
Nevada Power Company d/b/a NV Energy
Niguel Energy Company
NMA, LLC
NNGC Acquisition LLC
Norcon Holdings, Inc.
Northern Aurora Inc.
Northern Consolidated Power, Inc.
Northern Natural Gas Company
NRS Referral Services, LLC
NV Energy, Inc.
NVE Holdings, LLC

NVE Insurance Co, Inc.
NW Referral Services, LLC
PCRE, L.L.C.
PFR Staffers, LLC
Pickford Escrow Company, Inc.
Pickford Holdings, LLC
Pickford Real Estate, Inc.
Pickford Services Company, Inc.
Pilot Butte, LLC
Pinon Pine Corporation
Pinon Pine Investment Company
Pinyon Pines I Holding Company, LLC
Pinyon Pines II Holding Company, LLC
Pinyon Pines Wind I, LLC
Pinyon Pines Wind II, LLC
PNW Referral, LLC
PPW Staffers, LLC
Preferred Carolinas Realty, Inc.
Preferred Carolinas Title Agency, LLC
Priority Title Corporation
Professional Referral Organization, Inc.
PW Fox Holding LLC
PW Fox, LLC
Quad Cities Energy Company
Real Estate Knowledge Services, L.L.C.
Real Estate Links, LLC
Real Estate Referral Network, Inc.
Real Living Real Estate, LLC
Reece & Nichols Alliance, Inc.
Reece & Nichols Realtors, Inc.
Reece Commercial, Inc.
Referral Associates of Georgia, LLC
Referral Company of North Carolina, Inc.
Referral Network of IL LLC
Relocation Advantage Partners, LLC
RHL Referral Company, LLC
Roberts Brothers, Inc.
Roy H. Long Realty Company, Inc.
Rubloff Insurance Agency LLC
S.W. Hydro, Inc.
Salton Sea Funding Corporation
Salton Sea Minerals Corporation
Salton Sea Power Company
Salton Sea Power Generation Company
Salton Sea Power LLC
Salton Sea Royalty Company
San Diego PCRE, Inc.
San Felipe Energy Company
Saranac Energy Company, Inc.
SECI Holdings, Inc.
Semonin Realtors, Inc.
Shorebreak Holdings II, LLC
Sierra Gas Holding Company
Sierra Pacific Power Company d/b/a NV Energy
Solar Star 3, LLC
Solar Star California XIX, LLC
Solar Star California XX, LLC
Solar Star Funding, LLC
Solar Star Projects Holdings, LLC
Southwest Relocation, LLC
SSC XIX, LLC
SSC XX, LLC
The Escrow Firm
The Referral Company
TIAC LLC
TitleSouth, LLC
TLTC LLC
Topaz Solar Farms, LLC
TPZ Holding, LLC
TRMC LLC
Two Rivers, Inc.
TX Jumbo Road Wind, LLC

VPC Geothermal LLC
Vulcan Power Company
Vulcan/BN Geothermal Power Company
Wailuku Holding Company LLC
Wailuku Investment LLC
Wailuku River Hydroelectric Power Co, Inc.
Walnut Ridge Wind, LLC
Wm Broughton, LLC

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

Berkshire Hathaway Inc. Sub-Group:
121 Acquisition Co., LLC
121 Development, Inc.
21 SPC, Inc.
2150 Cobb Development, Inc.
21st Communities, Inc.
21st Mortgage Corporation
2701 Camelback Development, Inc.
3Wire Group Inc.
6991 Development, Inc.
Accurate Installations, Inc.
Acme Brick Company
Acme Brick DFW, Inc.
Acme Brick Sales Company
Acme Brick Tile & Stone, Inc.
Acme Building Brands, Inc.
Acme Investment Company
Acme Management Company
Acme Ochs Brick and Stone, Inc.
Acme Services Company, L.P.
Active Organics, Inc.
Adalet/Scott Fetzer Company
AEG Processing Center No. 35, Inc.
AEG Processing Center No. 58, Inc.
Affiliated Agency Operations Co.
Affordable Housing Partners, Inc.
AJF Warehouse Distributors, Inc.
AL/TEX Homes, Inc.
Albacor Shipping (USA) Inc.
Albecca, Inc.
Alexander Road Insurance Agency, Inc.
Alpha Cargo Motor Express, Inc.
American All Risk Insurance Services Inc.
American Commercial Claims Administrators Inc.
American Dairy Queen Corporation
American Employers Group, Inc.
AmGUARD Insurance Company
Applied Group Insurance Holdings, Inc.
Applied Investigations Inc.
Applied Logistics, Inc.
Applied Premium Finance, Inc.
Applied Processing Center No. 60, Inc.
Applied Risk Services of New York, Inc.
Applied Risk Services, Inc.
Applied Underwriters Captive Risk Assurance Company, Inc.
Applied Underwriters, Inc.
Artform International Inc.
Astrex Electronics, Inc.
Astrex Holding Company
Atlanta International Insurance Company
AU Captive Risk Assurance Co.
AU Holding Company, Inc.
Baroness Small Estates, Inc.
Bayport Systems, Inc.
BCC Development, Inc.
Ben Bridge Jeweler, Inc.
Benjamin Moore & Co.
Benson Industries, Inc.
Benson, Ltd.

Berkshire Hathaway Assurance Corporation
Berkshire Hathaway Automotive Inc.
Berkshire Hathaway Credit Corporation
Berkshire Hathaway Direct Insurance Company
Berkshire Hathaway Finance Corporation
Berkshire Hathaway Global Insurance Services, LLC
Berkshire Hathaway Homestate Insurance Company
Berkshire Hathaway Inc.
Berkshire Hathaway Life Insurance Company of Nebraska
Berkshire Hathaway Specialty Concierge, LLC
Berkshire Hathaway Specialty Insurance Company
Berkshire Indemnity Group Inc.
BH Columbia Inc.
BH Credit LLC
BH Finance, Inc.
BH Media Group Holdings, Inc.
BH Media Group, Inc.
BH Shoe Holdings, Inc.
BH, LLC
BHA Real Estate Holdings, LLC
BHG Life Insurance Company
BHG Structured Settlements, Inc.
BHSF, Inc.
Blue Chip Stamps, Inc.
BN Leasing Corporation
BNJ NetJets, Inc.
BNSF Communications, Inc.
BNSF Logistics International, Inc.
BNSF Railway Company
BNSF Railway International Services, Inc.
BNSF Spectrum, Inc.
Boat America Corporation
Boat Owners Association of the United States
Boat/U.S, Inc.
Boot Royalty Company
Borrego Holdings, Inc.
Borsheim Jewelry Company, Inc.
BR Agency, Inc.
Brainy Toys, Inc.
Brilliant National Services, Inc.
Brooks Sports, Inc.
Brookwood Insurance Company
BuilderMT, Inc.
Burlington Northern Railroad Holdings, Inc.
Burlington Northern Santa Fe British Columbia, Ltd.
Burlington Northern Santa Fe Insurance Company, Ltd.
Burlington Northern Santa Fe Manitoba, Inc.
Burlington Northern Santa Fe, LLC
Business Wire, Inc.
BWVT Motors, Inc.
C & R Insurance Services, Inc.
California Insurance Company
Camp Manufacturing Company
Campbell Hausfeld Holdings. Inc.
Campbell Hausfeld/Scott Fetzer Company
Cannon Equipment LLC
Carefree/Scott Fetzer Company
Cavalier Homes, Inc.
CCC Lonestar LLC
Central States Indemnity Co. of Omaha
Central States of Omaha Companies, Inc.
Charter Brokerage Holdings Corp.
Chatwell, Inc.
Chemtool Incorporated
Chippewa Shoe Company
CJE II
Claims Services, Inc.
Clayton Commercial Buildings, Inc.
Clayton Education Corp.
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.
CMH Transport, Inc.
Columbia Insurance Company
Combined Claims Services, Inc.
Commercial Casualty Insurance Company
Commercial General Indemnity, Inc.
Complementary Coatings Corporation
Consolidated Health Plans Inc.
Continental Divide Insurance Company
Continental Indemnity Company
Cornelius Inc.
Cornelius Renew, Inc.
Cort Business Services Corporation
Courtesy Dealership Property, Inc.
Coverage Dynamics Group, Inc.
CoverYourBusiness.com Inc.
Criterion Insurance Agency
CSI Life Insurance Company
CTB Credit Corp
CTB Inc.
CTB International Corp
CTB IW Inc.
CTB Midwest Inc.
CTB MN Investments
Cubic Designs, Inc.
Cumberland Asset Management, Inc.
Cypress Insurance Company
D.I. Properties Inc.
DAA Development, Inc.
Dairy Queen Corporate Stores, Inc.
Dairy Queen Of Georgia, Inc.
DCI Marketing Inc.
Delta Wholesale Liquors, Inc.
Denver Brick Company
DL Trading Holdings I, Inc.
DQ Funding Corporation
DQ Joint Venture Stores, Inc.
DQ Managed Stores, Inc.
DQ Wholly-Owned Stores, Inc.
DQF, Inc.
DQGC, Inc.
DragonFly Aeronautics LLC
Dynamic Development, Inc.
EastGUARD Insurance Company
Eco Color Company
Ecodyne Corporation
Ellis & Watts Global Industries, Inc.
Elm Street Corporation
Empire Distributors of North Carolina, Inc.
Empire Distributors, Inc.
Executive Jet Management, Inc.
Exsif Worldwide, Inc.
ExtruMed, Inc.
Faraday Capital Limited
FFBH Development, Inc.
Finial Holdings, Inc.
Finial Reinsurance Company
First American Carriers, Inc.
First Berkshire Hathaway Life Insurance Company
FlightSafety Capital Corp.
FlightSafety Development Corp.
FlightSafety International Inc.
FlightSafety New York, Inc.
FlightSafety Properties, Inc.
FlightSafety Services Corporation
Floors, Inc.

Fontaine Commercial Trailer, Inc.
Fontaine Engineered Products, Inc.
Fontaine Fifth Wheel Company
Fontaine Modification Company
Fontaine Spray Suppression Company
Fontaine Trailer Company LLC
Fontaine Truck Equipment Company LLC
Fontana Wood Products, Inc.
Footwear Investment Company
Forest River Financial Services, Inc.
Forest River Holdings, Inc.
Forest River Manufacturing LLC
Forest River, Inc.
Freedom Warehouse Corp.
FreightWise, Inc.
Fruit of the Loom Direct, Inc.
Fruit of the Loom Trading Company
Fruit of the Loom, Inc.
Fruit of the Loom, Inc. (Sub)
FTL Regional Sales Co., Inc.
Garan Central America Corp.
Garan Incorporated
Garan Manufacturing Corp.
Garan Services Corp
Gateway Underwriters Agency, Inc.
GEICO Advantage Insurance Company
GEICO Casualty Co.
GEICO Choice Insurance Company
GEICO Corporation
GEICO General Insurance Co.
GEICO Indemnity Co.
GEICO Insurance Agency
GEICO Marine Insurance Company
GEICO Products, Inc.
GEICO Secure Insurance Company
Gen Re Intermediaries Corporation
General Re Corporation
General Re Financial Products Corporation
General Re Life Corporation
General Re New England Asset Management
General Reinsurance Corporation
General Star Indemnity Company
General Star Management Company
General Star National Insurance Company
Genesis Insurance Company
Genesis Management and Insurance Services Corporation
Giles Industries, Inc.
Government Employees Financial Corp.
Government Employees Insurance Co.
GRD Holdings Corporation
GUARDco, Inc.
H. H. Brown Shoe Company, Inc.
H.J. Justin & Sons, Inc.
Halex/Scott Fetzer Company
Hallmark Sweet, Inc.
Hawthorn Life International, Ltd.
HDS Redevelopment Corporation
HeatPipe Technology, Inc.
Helzberg's Diamond Shops, Inc.
Henley Holdings, LLC
HFWBH Development, Inc.
HG-Power Plant. Inc.
Hohmann & Barnard, Inc.
Homefirst Agency, Inc.
Homemakers Plaza, Inc.
Horizon Wine & Spirits - Chattanooga, Inc.
Horizon Wine & Spirits - Nashville, Inc.
IdeaLife Insurance Company
Illinois Insurance Company
Ingersoll Cutting Tool Company
Innovative Building Products, Inc.
International American Group Inc.

International Dairy Queen, Inc.
International Insurance Underwriters, Inc.
International Traders, Inc.
Intrepid JSB, Inc.
Ironwood Plastics Inc.
Iscar Metals Inc.
ITTI Group USA Holdings, Inc.
ITTI Investment Holdings, Inc.
J.L. Mining Company
J.S Justin, Inc.
JDS Properties, 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.
Kahn Ventures, Inc.
Karmelkorn Shoppes, Inc.
Kova Solutions, Inc.
L.A. Terminals, Inc.
Leesburg Yarn Mills, Inc.
Lipotec Group Corp.
LMG Ventures, LLC
Lockwood Street Urban Renewal Corporation
Los Angeles Junction Railway Company
LSP Holding, Inc.
Lubricant Investments, Inc.
Lubrizol Advanced Materials China, Inc.
Lubrizol Advanced Materials Gibraltar, Inc.
Lubrizol Advanced Materials Holding Corporation
Lubrizol Advanced Materials International, Inc.
Lubrizol Advanced Materials, Inc.
Lubrizol Enterprises, Inc.
Lubrizol Inter-Americas Corporation
Lubrizol International Management Corporation
Lubrizol Oilfield Solutions, Inc.
Lubrizol Overseas Trading Corporation
Lubrizol Specialty Products, Inc.
M & C Products, Inc.
M&M Tradition Holdings Corp.
Mapletree Transportation, Inc.
Marathon Suspension Systems, Inc.
Marmon Beverage Technologies, Inc.
Marmon Crane Services, Inc.
Marmon Distribution Services, Inc.
Marmon Energy Services Company
Marmon Engineered Components Company
Marmon Foodservice Technologies LLC
Marmon Holdings, Inc.
Marmon Merchandising Holdings, Inc.
Marmon Retail Products, Inc.
Marmon Retail Store Equipment LLC
Marmon Retail Technologies Company
Marmon Tubing, Fittings & Wire Products, Inc.
Marmon Water, Inc.
Marmon Wire & Cable, Inc.
Marmon-Herrington Company
Marquis Jet Holdings, Inc.
Marquis Jet Partners, Inc.
Martin Mills, Inc.
Maryland Ventures, Inc.
McCarty-Hull Cigar Company, Inc.
McLane Beverage Distribution, Inc.
McLane Beverage Holding, 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 Ohio, Inc.
McLane Southern, Inc.
McLane Suneast, Inc.
McLane Western, Inc.
Meadowbrook Meat Company, Inc.
Medical Protective Finance Corporation
Medical Protective Insurance Services, Inc.
MedPro Group, Inc.
MedPro Risk Retention Services, Inc.
Meyn LLC
Midwest Northwest Properties, Inc.
Miller-Sage, Inc.
Mindware Corporation
MiTek Holdings, Inc.
MiTek Industries, Inc.
MiTek USA, Inc.
Montana Retail Properties, Inc.
Morgantown-National Supply, Inc.
Mount Vernon Fire Insurance Company
Mount Vernon Specialty Insurance Company
Mouser Electronics, Inc.
MPP Administrators, Inc.
MPP Co., Inc.
MPP Pipeline Corporation
MS Property Company
MVVT Development, Inc.
MW Wholesale, Inc.
National Fire & Marine Insurance Company
National Indemnity Company
National Indemnity Company of Mid-America
National Indemnity Company of the South
National Liability & Fire Insurance Company
Nationwide Uniforms
Nebraska Furniture Mart, Inc.
NetJets Aviation, Inc.
NetJets Europe Holdings, LLC
NetJets Inc.
NetJets International, Inc.
NetJets Large Aircraft, Inc.
NetJets Sales, Inc.
NetJets Services, Inc.
NetJets U.S., Inc.
NFM of Kansas, Inc.
NFM SERVICES, LLC
NJE Holdings, LLC
NJI Sales, Inc.
Nocona Boot Company
NorGUARD Insurance Company
North American Casualty Co.
Northern States Agency, Inc.
Norvell Electronics, Inc.
Noveon Hilton Davis, Inc.
Oak River Insurance Company
Old United Casualty Company
Omaha World-Herald Company
Orange Julius Of America
Oriental Trading Company, Inc.
OTC Brands, Inc.
OTC Direct, Inc.
OTC Worldwide Holdings, Inc.
P Chem, Inc.
Particle Sciences, Inc.
Penn Coal Land, Inc.
Pennsylvania Insurance Company
Perfection Hy-Test Company
PFVT Development, Inc.
Pine Canyon Land Company
PJR Management, Inc.
Plaza Financial Services Co.

Plaza Resources Co.
PLICO
PLICO Financial, Inc.
PLICO Sponsored Captive Insurance - Cell 1
PLICO Sponsored Captive Insurance Co.
Precision Brand Products, Inc.
Precision Steel Warehouse - Charlotte
Precision Steel Warehouse, Inc.
Princeton Advertising & Marketing Group, Inc.
Princeton Insurance Company
Princeton Risk Protection, Inc.
Priority One Financial Services, Inc.
Pro Installations, Inc.
Procrane Holdings, Inc.
Professional Datasolutions, Inc.
Promesa Health, Inc.
QS Partners LLC
R.C. Willey Home Furnishings
Rabun Apparel, Inc.
Radnor Specialty Insurance Company
Railserve, Inc.
Railsplitter Holdings Corporation
RCP Investment, Inc.
Red River Providers Association RPG
Redwood Fire and Casualty Insurance Company
RENTCO Trailer Corporation
Resolute Management Inc.
Richline Group, Inc.
Ridgeline Captive Management, Inc.
Ringwalt & Liesche Co.
Rio Grande, Inc.
Roxell USA, Inc.
Royal Cargo Line, Inc.
Rush Air Inc.
Russell Athletic Corporation
Sager Electrical Supply Co. Inc.
Salado Sales, Inc.
Santa Fe Pacific Insurance Company
Santa Fe Pacific Pipeline Holdings, Inc.
Santa Fe Pacific Pipelines, Inc.
Santa Fe Pacific Railroad Company
Scott Fetzer Financial Group, Inc.
ScottCare Corporation
See's Candies, Inc.
Sees Candy Shops, Incorporated
Seventeenth Street Realty, Inc.
SFEG Corp.
SFVT Development, 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.
Shaw Retail Properties, Inc.
Shaw Transport, Inc.
SHX Flooring, Inc.
SidePlate Systems, Inc.
Smilemakers Canada Inc.
Smilemakers, Inc.
SN Management, Inc.
Soco West, Inc.
Somerset Services, Inc.
Southern Energy Homes, Inc.
Spectra Contract Flooring Puerto Rico, Inc.
SSP-SiMatrix Inc.
SSS Acquisition Inc.
SSS Acquisition Sub, Corp
Stahl/Scott Fetzer Company
Star Furniture Company
Star Lake Railroad Company

Stern/Leach Company
Strategic Staff Management, Inc.
Syrgis Holdings, Inc.
Taegutec Inc.
TBS USA, Inc.
Texas Insurance Company
The Ben Bridge Corporation
The BN and SF Railway de Mexico, S.A. de C.V.
The Buffalo News, Inc.
The BVD Licensing Corporation
The Fechheimer Brothers Co.
The Indecor Group, Inc.
The Lubrizol Corporation
The Medical Protective Company
The Pampered Chef, Ltd.
The Scott Fetzer Company
The Wilkins Corporation
The Zia Company
TMI Climate Solutions, Inc.
TOHVT Development, Inc.
Tony Lama Company
Tool-Flo Manufacturing, Inc.
Top Five Club, Inc.
Total Quality Apparel Resources
TPC European Holdings, LTD.
TPC North America, Ltd.
Transco, Inc.
Transportation Technology Services, Inc.
TRH Holding Corp.
Triangle Suspension Systems, Inc.
TSE Brakes, Inc.
TTI, Inc.
Tucker Safety Products, Inc.
TXFM, Inc.
TXVT Development, Inc.
U.S. Investment Corporation
U.S. Underwriters Insurance Co.
UCFS Europe Company
Unified Supply Chain, Inc.
Uni-Form Components Co.
Union Sales, Inc.
Union Tank Car Company
Union Underwear Co., Inc.
Unione Italiana Reinsurance Company of America, Inc.
United Consumer Financial Services Company
United Direct Finance, Inc.
United States Aviation Underwriters, Incorporated
United States Liability Insurance Company
UTLX Company
Van Enterprises, Inc.
Vanderbilt ABS Corp.
Vanderbilt Mortgage and Finance, Inc.
Vanderbilt Property&Casualty Insurance Co., Ltd.
Vanderbilt SPC, Inc.
Vanity Fair, Inc.
Veritas Insurance Group, Inc.
Vesta Funding, Inc.
Vesta Intermediate Funding, Inc.
VFI-Mexico, Inc.
Vision Retailing, Inc.
VNDR Development, Inc.
VT Insurance Acquisition Sub Inc.
Warwick Chemicals USA, Inc.
Wayne/Scott Fetzer Company
Webb Wheel Products, Inc.
Western Builders Supply, Inc.
Western Fruit Express Company
Western/Scott Fetzer Company
WestGUARD Insurance Company
Whittaker, Clark & Daniels, Inc.
WMC Corp.
World Book Encyclopedia, Inc.

World Book, Inc.
World Book/Scott Fetzer Company
World Investments, Inc.
Worldwide Containers, Inc.
WPLG, Inc.
X-L-Co., Inc.
XTRA Companies, Inc.
XTRA Corporation
XTRA Finance Corporation
XTRA Intermodal, Inc.

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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 Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	Federal:					
2	Income	148,956		125,321,975	19,256,508	106,147,921
3	FICA	664,385	5,000	36,522,444	36,463,266	
4	Unemployment	5,257		239,266	281,536	
5	Excise Tax - Coal	7,385		119,300	126,685	
6	Foreign Withholding Taxes			1,522,888		
7	Subtotal	825,983	5,000	163,725,873	56,127,995	106,147,921
8						
9	State:					
10						
11	Arizona:					
12	Property	1,891,464		3,649,984	3,716,456	
13	Income			866,625	776,758	89,867
14	Subtotal	1,891,464		4,516,609	4,493,214	89,867
15						
16	California:					
17	Property			2,309,036	2,309,036	
18	Unemployment	2,207		30,348	32,625	
19	Franchise-Income			1,235,784	797,578	438,206
20	Use	2,641		151,826	96,067	
21	Local Franchise	1,278,860		1,094,371	1,128,715	
22	Subtotal	1,283,708		4,821,365	4,364,021	438,206
23						
24	Colorado:					
25	Property	2,190,000		2,079,523	2,159,523	
26	Income			-216		-216
27	Subtotal	2,190,000		2,079,307	2,159,523	-216
28						
29	Idaho:					
30	Property	2,406,767		5,548,923	4,830,799	
31	Income			2,306,972	1,686,970	620,002
32	KWh	17,016		37,280	39,156	
33	Unemployment	1,423		36,450	36,545	
34	Use	14,461		223,953	225,196	
35	Subtotal	2,439,667		8,153,578	6,818,666	620,002
36						
37	Montana:					
38	Property	2,155,918		4,700,074	4,507,433	
39	Corporate License-Income			157,472	62,827	94,645
40	Unemployment			720	720	
41	TOTAL	39,025,536	12,376,039	393,028,516	271,448,063	118,979,745

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
66,502		121,054,868			4,267,107	2
723,563	5,000				36,522,444	3
-37,013					239,266	4
					119,300	5
1,522,888					1,522,888	6
2,275,940	5,000	121,054,868			42,671,005	7
						8
						9
						10
						11
1,824,992		3,649,984				12
		856,303			10,322	13
1,824,992		4,506,287			10,322	14
						15
						16
		2,193,537			115,499	17
-70					30,348	18
		1,206,921			28,863	19
58,400					151,826	20
1,244,516		1,094,371				21
1,302,846		4,494,829			326,536	22
						23
						24
2,110,000		1,754,352			325,171	25
		-230			14	26
2,110,000		1,754,122			325,185	27
						28
						29
3,124,891		5,529,969			18,954	30
		2,267,691			39,281	31
15,140		37,280				32
1,328					36,450	33
13,218					223,953	34
3,154,577		7,834,940			318,638	35
						36
						37
2,348,559		4,700,074				38
		153,741			3,731	39
					720	40
41,847,694	12,597,489	331,407,278			61,621,238	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	Energy License	62,000		241,715	241,715	
2	Wholesale Energy	44,000		172,224	172,224	
3	Subtotal	2,261,918		5,272,205	4,984,919	94,645
4						
5	Nevada:					
6	Commerce Tax			10,000		
7	Subtotal			10,000		
8						
9	New Mexico:					
10	Property			22,851	22,851	
11	Income			-19,267	105	-19,372
12	Subtotal			3,584	22,956	-19,372
13						
14	Oregon:					
15	Property		11,851,143	23,748,743	23,762,422	
16	Unemployment	53,901		1,454,515	1,462,047	
17	Excise-Income			9,235,765	3,773,226	5,462,539
18	City of Portland-Income			23,449	23,981	-532
19	Department of Energy		519,896	1,247,564	1,455,335	
20	Tri-Met	427,121		1,051,047	1,082,106	
21	Lane County			1,282	1,282	
22	Franchise	4,621,877		28,784,862	28,866,802	
23	Subtotal	5,102,899	12,371,039	65,547,227	60,427,201	5,462,007
24						
25	Texas:					
26	Unemployment			243	243	
27	Subtotal			243	243	
28						
29	Utah:					
30	Property	559,037		74,453,917	74,283,223	
31	Income			11,841,256	5,694,571	6,146,685
32	Unemployment	7,580		260,302	262,790	
33	Navajo Nation			610	610	
34	Use	403,158		4,123,322	4,066,518	
35	Subtotal	969,775		90,679,407	84,307,712	6,146,685
36						
37	Washington:					
38	Property	10,290,000		11,341,694	10,381,694	
39	Unemployment	1,921		149,647	140,937	
40	Business & Occupation	2,714		24,000	24,324	
41	TOTAL	39,025,536	12,376,039	393,028,516	271,448,063	118,979,745

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
62,000		241,715				1
44,000		172,224				2
2,454,559		5,267,754			4,451	3
						4
						5
10,000		10,000				6
10,000		10,000				7
						8
						9
		22,851				10
		-19,965			698	11
		2,886			698	12
						13
						14
	11,864,822	22,872,553			876,190	15
46,369					1,454,515	16
		9,003,414			232,351	17
		22,789			660	18
	727,667	1,247,564				19
396,062					1,051,047	20
					1,282	21
4,539,937		28,784,862				22
4,982,368	12,592,489	61,931,182			3,616,045	23
						24
						25
					243	26
					243	27
						28
						29
729,731		69,285,776			5,168,141	30
		11,577,347			263,909	31
5,092					260,302	32
		610				33
459,962					4,123,322	34
1,194,785		80,863,733			9,815,674	35
						36
						37
11,250,000		11,206,730			134,964	38
10,631					149,647	39
2,390		24,000				40
41,847,694	12,597,489	331,407,278			61,621,238	41

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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	Public Utility	1,325,000		13,134,413	13,124,413	
2	Natural Gas Use Tax	354,168		1,252,182	1,503,066	
3	Use	90,103		856,172	875,578	
4	Forest excise tax			24,970	24,970	
5	Subtotal	12,063,906		26,783,078	26,074,982	
6						
7	Wyoming:					
8	Property	7,489,054		15,123,809	15,054,067	
9	Wind Generation Tax	2,027,954		1,738,070	1,998,855	
10	Unemployment	5,157		88,914	91,325	
11	Franchise	285,300		1,950,466	1,960,866	
12	Use	148,763		2,001,436	2,010,578	
13	Annual Report			70,261	70,261	
14	Subtotal	9,956,228		20,972,956	21,185,952	
15						
16	State Other	20,512		-17,909		
17						
18	Miscellaneous:					
19	Goshute Possessory			23,401	23,401	
20	Sho-Ban Possessory			241,948	241,948	
21	Navajo Possessory	19,476		39,579	39,265	
22	Ute Possessory			38,782	38,782	
23	Crow Possessory			70,632	70,632	
24	Umatilla Possessory			66,651	66,651	
25	Subtotal	39,988		463,084	480,679	
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	39,025,536	12,376,039	393,028,516	271,448,063	118,979,745

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
1,335,000		13,134,413				1
103,284					1,252,182	2
70,697					856,172	3
					24,970	4
12,772,002		24,365,143			2,417,935	5
						6
						7
7,558,796		15,099,653			24,156	8
1,767,169		1,738,070				9
2,746					88,914	10
274,900		1,950,466				11
139,621					2,001,436	12
		70,261				13
9,743,232		18,858,450			2,114,506	14
						15
2,603		-17,909				16
						17
						18
		23,401				19
		241,948				20
19,790		39,579				21
		38,782				22
		70,632				23
		66,651				24
22,393		463,084				25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
41,847,694	12,597,489	331,407,278			61,621,238	41

Schedule Page: 262 Line No.: 2 Column: f
Represents a reclassification of a portion of the balance at end of year to Account 146, Accounts receivable from associated companies.

Schedule Page: 262 Line No.: 2 Column: l
Account 409.2, Income tax, other income and deductions, which represents federal income tax applicable to other income and deductions.

Schedule Page: 262 Line No.: 3 Column: l
Payroll taxes are generally charged to operations and maintenance expense and construction work in progress.

Schedule Page: 262 Line No.: 4 Column: l
Payroll taxes are generally charged to operations and maintenance expense and construction work in progress.

Schedule Page: 262 Line No.: 5 Column: l
Account 151, Fuel stock

Schedule Page: 262 Line No.: 6 Column: l
$1,271,911 Account 426.3, Penalties
250,977 Account 431, Other interest expense
$1,522,888

Schedule Page: 262 Line No.: 13 Column: f
Represents a reclassification of the balance at end of year to Account 143, Other accounts receivable.

Schedule Page: 262 Line No.: 13 Column: l
Account 409.2, Income tax, other income and deductions, which represents state income tax applicable to other income and deductions.

Schedule Page: 262 Line No.: 17 Column: l
$113,930 Account 408.2, Taxes other than income taxes, other income and deductions
1,569 Account 589, Rents
$115,499

Schedule Page: 262 Line No.: 18 Column: l
Payroll taxes are generally charged to operations and maintenance expense and construction work in progress.

Schedule Page: 262 Line No.: 19 Column: f
Represents a reclassification of a portion of the balance at end of year to Account 146, Accounts receivable from associated companies.

Schedule Page: 262 Line No.: 19 Column: l
Account 409.2, Income tax, other income and deductions, which represents state income tax applicable to other income and deductions.

Schedule Page: 262 Line No.: 20 Column: l
Charged to same account as related goods.

Schedule Page: 262 Line No.: 25 Column: l
$ 784 Account 408.2, Taxes other than income taxes, other income and deductions
324,387 Account 107, Construction work in progress
$325,171

Schedule Page: 262 Line No.: 26 Column: f
Represents a reclassification of the balance at end of year to Account 143, Other accounts receivable.

Schedule Page: 262 Line No.: 26 Column: l
Account 409.2, Income tax, other income and deductions, which represents state income tax applicable to other income and deductions.

Schedule Page: 262 Line No.: 30 Column: l
$ 1,132 Account 408.2, Taxes other than income taxes, other income and deductions
17,822 Account 107, Construction work in progress
$ 18,954

Schedule Page: 262 Line No.: 31 Column: f

Represents a reclassification of a portion of the balance at end of year to Account 146, Accounts receivable from associated companies.

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

Account 409.2, Income tax, other income and deductions, which represents state income tax applicable to other income and deductions.

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

Payroll taxes are generally charged to operations and maintenance expense and construction work in progress.

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

Charged to same account as related goods.

Schedule Page: 262 Line No.: 39 Column: f

Represents a reclassification of a portion of the balance at end of year to Account 146, Accounts receivable from associated companies.

Schedule Page: 262 Line No.: 39 Column: l

Account 409.2, Income tax, other income and deductions, which represents state income tax applicable to other income and deductions.

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

Payroll taxes are generally charged to operations and maintenance expense and construction work in progress.

Schedule Page: 262.1 Line No.: 11 Column: f

Represents a reclassification of the balance at end of year to Account 143, Other accounts receivable.

Schedule Page: 262.1 Line No.: 11 Column: l

Account 409.2, Income tax, other income and deductions, which represents state income tax applicable to other income and deductions.

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

$ 22,107	Account 408.2, Taxes other than income taxes, other income and deductions
137,374	Account 589, Rents
716,709	Account 107, Construction work in progress
$876,190	

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

Payroll taxes are generally charged to operations and maintenance expense and construction work in progress.

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

Represents a reclassification of a portion of the balance at end of year to Account 146, Accounts receivable from associated companies.

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

Account 409.2, Income tax, other income and deductions, which represents state income tax applicable to other income and deductions.

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

Represents a reclassification of a portion of the balance at end of year to Account 146, Accounts receivable from associated companies.

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

Account 409.2, Income tax, other income and deductions, which represents state income tax applicable to other income and deductions.

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

Payroll taxes are generally charged to operations and maintenance expense and construction work in progress.

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

Payroll taxes are generally charged to operations and maintenance expense and construction work in progress.

Schedule Page: 262.1 Line No.: 26 Column: l

Payroll taxes are generally charged to operations and maintenance expense and construction work in progress.

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

$ 63,083 Account 408.2, Taxes other than income taxes, other income and deductions
524 Account 589, Rents
3,055,445 Account 107, Construction work in progress
2,049,089 Account 151, Fuel stock
$5,168,141

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

Represents a reclassification of a portion of the balance at end of year to Account 146, Accounts receivable from associated companies.

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

Account 409.2, Income tax, other income and deductions, which represents state income tax applicable to other income and deductions.

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

Payroll taxes are generally charged to operations and maintenance expense and construction work in progress.

Schedule Page: 262.1 Line No.: 34 Column: l

Charged to same account as related goods.

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

$ 37,833 Account 408.2, Taxes other than income taxes, other income and deductions
97,131 Account 107, Construction work in progress
$134,964

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

Payroll taxes are generally charged to operations and maintenance expense and construction work in progress.

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

Account 151, Fuel stock

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

Charged to same account as related goods.

Schedule Page: 262.2 Line No.: 4 Column: l

Account 408.2, Taxes other than income taxes, other income and deductions

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

$ 3,702 Account 408.2, Taxes other than income taxes, other income and deductions
17,066 Account 589, Rents
3,388 Account 107, Construction work in progress
$24,156

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

Payroll taxes are generally charged to operations and maintenance expense and construction work in progress.

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

Charged to same account as related goods.

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%	25,438,102			411.4, 420	5,113,907	
6	30%	269,158			420	11,696	
7	Idaho	123,994			411.4, 420	15,695	
8	TOTAL	25,831,254				5,141,298	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11	Idaho	1,382,683	190	601,685	420	168,262	-940
12	Total Nonutility	1,382,683		601,685		168,262	-940
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
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48							

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
20,324,195	38.82 and 30		5
257,462	24		6
108,299	38.82 and 30		7
20,689,956			8
			9
			10
1,815,166	30		11
1,815,166			12
			13
			14
			15
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			21
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			46
			47
			48

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

The electric utility subdivision of 10% accumulated deferred investment tax credits are as follows:

Acct. Sub. (a)	Beginning Balance (b)	Deferred for Yr. Acct. (c)	Deferred for Yr. Amount (d)	Allocat. to CY Acct. (e)	Allocat. to CY Amount (f)	Adj. (g)	Ending Balance (h)	Avg. Per. (i)
10%	$24,753,083	-	$ -	411.4(1)	$4,749,955	$ -	$20,003,128	38.82
10%	685,019	-	-	420(2)	363,952	-	321,067	30
	$25,438,102		$ -		$5,113,907	$ -	$20,324,195	

(1) Internal Revenue Code 46(f)2
(2) Internal Revenue Code 46(f)1

Schedule Page: 266 Line No.: 7 Column: b

The electric utility subdivision of Idaho accumulated deferred investment tax credits are as follows:

Acct. Sub. (a)	Beginning Balance (b)	Deferred for Yr. Acct. (c)	Deferred for Yr. Amount (d)	Allocat. to CY Acct. (e)	Allocat. to CY Amount (f)	Adj. (g)	Ending Balance (h)	Avg. Per. (i)
Idaho	$ 60,087	-	$ -	411.4(1)	$ 6,453	$ -	$ 53,634	38.82
Idaho	63,907	-	-	420(2)	9,242	-	54,665	30
	$ 123,994		$ -		$ 15,695	$ -	$ 108,299	

(1)Internal Revenue Code 46(f)2
(2)Internal Revenue Code 46(f)1

Schedule Page: 266 Line No.: 11 Column: g

Represents an adjustment to the balance at beginning of year credited to Account 190, Accumulated deferred income taxes.

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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 $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Working Capital Deposits	6,804,201	131	1,037,000	128,610	5,895,811
2						
3	Reclamation Costs - Trapper Mine	5,617,504			242,972	5,860,476
4						
5	Western Coal Carriers Benefits					
6	Obligation	12,417,000	131,232	699,443	73,443	11,791,000
7						
8	Program Incentives	268,873	921	154,403		114,470
9						
10	Deferred Compensation Plans	9,721,835	131,232,241	819,114	768,377	9,671,098
11						
12	Long-Term Incentive Plan	6,935,250	426.5	1,319,496	2,868,941	8,484,695
13						
14	Redding Contract (20)	550,096	456	550,096		
15						
16	Foote Creek Contract (15)	17,102	456	17,102		
17						
18	Regulated Environmental					
19	Liabilities	21,619,912		4,476,335	5,794,521	22,938,098
20						
21	Non-Regulated Environmental					
22	Liabilities	2,217,266		95,490	101,067	2,222,843
23						
24	Unearned Joint Use Pole					
25	Contact	2,915,426	454	6,223,719	6,172,814	2,864,521
26						
27	Misc. Security Deposits	1,900			1,500	3,400
28						
29	Lease Incentives	279,558	931	125,123	752,490	906,925
30						
31	Cowlitz/Lewis River O&M (1)	118,811	539	287,396	289,003	120,418
32						
33	Employee Housing Security Deposits	17,806	131, 545	4,031	4,200	17,975
34						
35	Cogeneration Bonds-Sunnyside	413,417				413,417
36						
37	Transmission Security Deposits	1,104,607	232	73,107	1,361,000	2,392,500
38						
39	Transmission Service Deposits	353,987	131, 232	1,284,514	1,164,809	234,282
40						
41	MCI F.O.G. Wire Lease (1)	557,813	454	3,345,900	3,345,705	557,618
42						
43	Unamortized Contract Values	110,203,561	242	12,284,939		97,918,622
44						
45	Loss Contingency - USA Power	119,103,601			2,480,165	121,583,766
46						
47	TOTAL	303,969,379		34,701,559	32,208,458	301,476,278

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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 $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Accrued Right-of-Way Obligations	2,249,800			300,682	2,550,482
2						
3	Navajo Tribal Utility Authority					
4	Escrow	480,053			95	480,148
5						
6	Facility Use Fee (2)		456	4,167	100,000	95,833
7						
8	Eagle Mountain Contract					
9	Liability (2)		555	1,900,184	6,008,064	4,107,880
10						
11	Energy Supply Management					
12	Deferral				250,000	250,000
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
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41						
42						
43						
44						
45						
46						
47	TOTAL	303,969,379		34,701,559	32,208,458	301,476,278

Schedule Page: 269 Line No.: 8 Column: a

The weighted average life is five years.

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

Account 131, Cash
Account 182.3, Other regulatory assets
Account 232, Accounts payable

Schedule Page: 269 Line No.: 22 Column: c

Account 131, Cash
Account 232, Accounts payable
Account 426.5, Other deductions

Schedule Page: 269 Line No.: 25 Column: a

The weighted average life is one year.

Schedule Page: 269 Line No.: 29 Column: a

The weighted average life is 10 years.

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

1. Report the information called for below concerning the respondent’s accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	252,151,842	37,473,042	3,637,886
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	252,151,842	37,473,042	3,637,886
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	252,151,842	37,473,042	3,637,886
18	Classification of TOTAL			
19	Federal Income Tax	221,987,431	32,628,468	2,840,935
20	State Income Tax	30,164,411	4,844,574	796,951
21	Local Income Tax			

NOTES

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
						285,986,998	4
							5
							6
							7
						285,986,998	8
							9
							10
							11
							12
							13
							14
							15
							16
						285,986,998	17
							18
						251,774,964	19
						34,212,034	20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	4,244,780,923	719,875,460	544,311,157
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	4,244,780,923	719,875,460	544,311,157
6	Nonutility			
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	4,244,780,923	719,875,460	544,311,157
10	Classification of TOTAL			
11	Federal Income Tax	3,767,325,446	617,035,002	465,523,833
12	State Income Tax	477,455,477	102,840,458	78,787,324
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS						
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits: Account Credited (g)	Debits: Amount (h)	Credits: Account Debited (i)	Credits: Amount (j)	Balance at End of Year (k)	Line No.
							1
7,608,148	7,608,148	182.3	6,920,694	182.3	1,242,855	4,414,667,387	2
							3
							4
7,608,148	7,608,148		6,920,694		1,242,855	4,414,667,387	5
							6
							7
							8
7,608,148	7,608,148		6,920,694		1,242,855	4,414,667,387	9
							10
6,742,731	6,742,731		5,612,702		614,098	3,913,838,011	11
865,417	865,417		1,307,992		628,757	500,829,376	12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Regulatory Assets	610,798,415	136,781,706	133,029,618
4	Other	22,513,229	13,188,444	13,721,830
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	633,311,644	149,970,150	146,751,448
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)	633,311,644	149,970,150	146,751,448
20	Classification of TOTAL			
21	Federal Income Tax	557,584,936	132,438,884	129,605,219
22	State Income Tax	75,726,708	17,531,266	17,146,229
23	Local Income Tax			

NOTES

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
46,119,436	33,146,353		14,163,529		26,274,301	639,634,358	3
8,064,405	8,183,117	190, 283	18,057,833	190, 283	14,089,080	17,892,378	4
							5
							6
							7
							8
54,183,841	41,329,470		32,221,362		40,363,381	657,526,736	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
54,183,841	41,329,470		32,221,362		40,363,381	657,526,736	19
							20
47,755,038	36,438,407		28,260,538		35,428,550	578,903,244	21
6,428,803	4,891,063		3,960,824		4,934,831	78,623,492	22
							23

NOTES (Continued)

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

Account 182.3, Other regulatory assets
Account 190, Accumulated deferred income taxes
Account 283, Accumulated deferred income taxes-other

Schedule Page: 276 Line No.: 3 Column: i

Account 182.3, Other regulatory assets
Account 190, Accumulated deferred income taxes
Account 283, Accumulated deferred income taxes-other

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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 $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	DSM Balancing Account - WY	1,890,606		5,754,043	3,863,437	
2	Oregon Energy Conservation Charge	2,630,492	131,232	22,135,795	21,847,704	2,342,401
3	Deferred Excess Net Power Costs - WA Hydro	121,961			10,213	132,174
4	Deferred Excess RECs in Rates - OR	300,002	182.3	358,557	58,555	
5	Income Tax Reg. Liability - WA Flow Through				968,175	968,175
6	Investment Tax Credit Regulatory Liability	13,365,333	190	2,561,869	254	10,803,718
7	2014 Tax on Bonus Depreciation - WY				968,851	968,851
8	Solar Feed-In Tariff Deferral - CA	945,656	440,442,444	88,589	672,994	1,530,061
9	Solar Incentive Program - UT	10,116,877		3,479,769	7,198,012	13,835,120
10	Renewable Portfolio Standards Compliance - OR (1)	104,972	555	143,401	71,805	33,376
11	Deferred Independent Evaluator Fee - UT (1)	62,151	923	62,151		
12	Alternative Rate for Energy (CARE) - CA	674,990	440,442,444	675,426	436	
13	Utah Home Energy Lifeline	2,496,697	142	1,330,986	99,239	1,264,950
14	Washington Low Income Program	1,302,789	142	312,185	623,900	1,614,504
15	Schedule 94-Distribution Safety Surcharge - OR	368,684	182.3,923	572,602	203,918	
16	2013 FERC Rate True-up - OR	6,025,257			5,772,211	11,797,468
17	Greenhouse Gas Allowance Revenues - CA	2,904,622	456,909,419	19,791,023	17,604,782	718,381
18	Asset Retirement Obligations Reg. Difference	9,943,988	230	5,426,273	2,909,400	7,427,115
19	BPA Balancing Account - WA				54,637	54,637
20	BPA Balancing Account - ID	2,314,967			1,328,270	3,643,237
21	Blue Sky - OR	2,824,724	440,442	1,603,945	1,777,435	2,998,214
22	Blue Sky - WA	346,504	440,442	320,068	180,518	206,954
23	Blue Sky - CA	133,454	440,442	23,833	70,795	180,416
24	Blue Sky - UT	3,163,064	440,442	1,560,852	2,987,234	4,589,446
25	Blue Sky - ID	123,561	440,442	18,442	52,197	157,316
26	Blue Sky - WY	351,243	440,442	70,499	203,301	484,045
27	Injuries & Damages Reserve - OR	2,085,033			3,134,946	5,219,979
28	Property Insurance Reserve - OR	1,036,454	924	8,105,022	7,068,568	
29	Property Insurance Reserve - ID	381,724	924	594	113,544	494,674
30	Property Insurance Reserve - UT	3,473,648	924	1,338,050	2,152,236	4,287,834
31	Depreciation Deferral - OR	854,995			999,943	1,854,938
32	Depreciation Deferral - WA (1)	668,497	440,442,444	609,011	208,848	268,334
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	71,012,945		76,342,985	83,206,358	77,876,318

Schedule Page: 278 Line No.: 1 Column: c

Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting

Schedule Page: 278 Line No.: 6 Column: a

Weighted average remaining life is 39 years.

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

Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting
Account 445, Other sales to public authorities

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	1,781,722,516	1,732,822,429
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,556,424,635	1,517,907,746
5	Large (or Ind.) (See Instr. 4)	1,435,608,671	1,430,453,424
6	(444) Public Street and Highway Lighting	19,942,747	20,446,444
7	(445) Other Sales to Public Authorities	16,902,061	17,499,523
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	4,810,600,630	4,719,129,566
11	(447) Sales for Resale	269,833,622	360,600,595
12	TOTAL Sales of Electricity	5,080,434,252	5,079,730,161
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	5,080,434,252	5,079,730,161
15	Other Operating Revenues		
16	(450) Forfeited Discounts	9,141,277	9,670,249
17	(451) Miscellaneous Service Revenues	5,531,248	5,956,286
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	19,100,070	17,827,613
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	28,322,174	65,097,066
22	(456.1) Revenues from Transmission of Electricity of Others	92,780,346	88,719,750
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	154,875,115	187,270,964
27	TOTAL Electric Operating Revenues	5,235,309,367	5,267,001,125

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
15,565,510	15,567,753	1,574,480	1,545,529	2
				3
17,261,893	17,073,151	201,691	200,454	4
21,402,658	21,933,602	33,305	33,373	5
140,686	143,147	3,496	3,534	6
270,465	281,624	3	3	7
				8
				9
54,641,212	54,999,277	1,812,975	1,782,893	10
8,889,451	10,270,247			11
63,530,663	65,269,524	1,812,975	1,782,893	12
				13
63,530,663	65,269,524	1,812,975	1,782,893	14

Line 12, column (b) includes $ 244,424,000 of unbilled revenues.

Line 12, column (d) includes 3,101,201 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, in 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, in this Form No. 1.

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

Account 451, Miscellaneous service revenues, includes the following items that were $250,000 or greater during the years ended December 31:

	2015	2014
Account service charges - disconnects/reconnects/returned check charges	$ 4,450,368	$ 4,450,910
Customer contract flat rate billings	1,038,530	1,464,397

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

Account 456, Other electric revenues, includes the following items that were $250,000 or greater during the years ended December 31:

	2015	2014
Amortization of California greenhouse gas allowance revenue	$ 11,212,184	$ 14,673,226
Energy exchange credits	10,083,346	9,010,784
Wind-based ancillary services	9,683,694	10,678,814
Flyash/by-product sales	5,099,321	4,998,296
Phase shifting equipment fee from Western Electricity Coordinating Council	1,130,302	656,040
Revenue from generation interconnection and transmission service request studies	1,077,939	1,162,487
Steam sales	665,336	988,645
Power sale and exchange agreements	550,096	685,320
Maintenance charges for work on transmission facilities	336,138	606,542
Service territory fixed cost recovery fee	317,733	302,725
Timber sales	(a)	426,135
Net profit on sales of materials and supplies inventory	(a)	381,251
Deferral of Oregon retail customers' allocated share of the incremental Open Access Transmission Tariff revenues associated with FERC Docket No. ER11-3643-000	(5,114,029)	(3,442,129)
Renewable energy credit sales, including amortization and deferrals	(6,901,286)	23,779,972

(a) The 2015 amount is less than $250,000.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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			1		
4	06LNX00311 - LINE EXT 80%GTY		1,949			
5	06NETMT135 - RES NET MTR	817	92,168	165	4,952	0.1128
6	06OALT015R-OUTD AR LGT SR	297	86,968	321	925	0.2928
7	06RESD000D-RES SRVC	157,531	20,984,005	17,178	9,171	0.1332
8	06RESDDL06-CA LOW INCOME	112,859	15,078,172	11,211	10,067	0.1336
9	06RGNSV025-CA SMALL GEN	1,254	268,460	473	2,651	0.2141
10	06RESD0DM9 - MULTI FAMILY	158	16,863	7	22,571	0.1067
11	06RESD0DS8-MULT FAM SBMET	1,079	93,425	16	67,438	0.0866
12	REVENUE_ACCT ADJ		-1,648,508			
13	06RESD00DN - RES SVC DEL NO	74,924	10,174,117	6,937	10,801	0.1358
14	06UPPL000R-BASE SCH FALL			2		
15	DSM REVENUE-RESIDENTIAL		1,379,271			
16	BLUE SKY REV-RESIDENTIAL		21,569			
17	SOLAR FEED-IN REVENUE		37,806			
18	UNBILLED REVENUE	1,925	464,000			0.2410
19						
20	IDAHO					
21	07LNX00010-MNTHLY 80%GUAR		1,139			
22	07LNX00035-ADV 80%MO GUAR		1,956			
23	07NETMT135 - ID RES NET MTR	1,604	164,990	120	13,367	0.1029
24	07OALCO007-CUST OWN LIGHT	10	3,832	1	10,000	0.3832
25	07OALT07AR-SECURITY AR LG	95	39,112	121	785	0.4117
26	07RESD0001-RES SRVC	437,253	49,768,610	47,503	9,205	0.1138
27	07RESD0036-RES SRVC-OPTIO	212,070	20,846,068	12,933	16,398	0.0983
28	07RGNSV06A-LRG GEN SVC-RES	206	16,149	1	206,000	0.0784
29	07RGNSV23A-SM GEN SVC-RES	7,747	880,986	966	8,020	0.1137
30	UNBILLED REV - UNCOLLECTIBLE		14,000			
31	REVENUE_ACCT ADJ		-60,450			
32	UNBILLED REVENUE	-2,042	-122,000			0.0597
33	DSM REVENUE-RESIDENTIAL		1,499,553			
34	DSM REVENUE-RESIDENTIAL GEN		-1			
35	BLUE SKY REV-RESIDENTIAL		16,393			
36						
37	OREGON					
38	01CHCK000R-RES CHECK MTR			1		
39	01COST0004 - 01RESD0004	4,829,655	284,486,743			0.0589
40	01COSTR023 RES GEN SRV CST	89,533	5,322,700			0.0594
41	TOTAL Billed	54,671,093	4,872,459,725	1,812,975	30,155	0.0891
42	Total Unbilled Rev.(See Instr. 6)	-29,881	1,172,000	0	0	-0.0392
43	TOTAL	54,641,212	4,873,631,725	1,812,975	30,139	0.0892

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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	01COSTR028, OR RES GEN SVC	42,729	2,542,845			0.0595
2	01FXRENEWR - FIXED		-2			
3	01HABIT004 - 01RESD0004	38,874	2,253,154			0.0580
4	01HABTR023-RES GEN SVC HAB	134	8,226			0.0614
5	01LNX00102-LINE EXT 80% G		9,948			
6	01LNX00109-REF/NREF ADV +		5,092			
7	01LNX00300 - LINE EXT 80% GTY		291			
8	01LNX00311 - LINE EXT 80% GTY		139			
9	01NETMT135-NET METERING		1,391,147	3,168		
10	01NMTOU135-TOU NET METERING		11,558	20		
11	01OALTB15R-OUTD AR LGT RE	2,269	366,805	2,589	876	0.1617
12	01PTOU0004 - 01RESD0004	15,737	956,381			0.0608
13	01PTOU0005-01RESEV05T TOU	1	57			0.0570
14	01RENEW004 - 01RESD0004	297,013	16,953,462			0.0571
15	01RENWR023-RENEW USAGE	397	24,293			0.0612
16	01RESD0004-RES SRVC		283,498,389	482,323		
17	01RESD004T - RES TIME OPT		820,509	1,131		
18	01RESEV05T-ELECT VEHICLE		91	1		
19	01RGNSB023-SMALL GENERAL		6,920,652	16,571		
20	01RGNSB028 -GEN SVC > 30 KW		1,267,262	200		
21	01RNETM023-NET METER RES		112,272	39		
22	01UPPL000R-BASE SCH FALL			3		
23	01VIR04136-VOLUME INCENTIVE		330,789	418		
24	OR GAIN ON SALE OF ASSET		45,857			
25	REVENUE ADJ - DEF NPC		-397,297			
26	REVENUE_ACCT ADJ		-2,906,750			
27	SOLAR FEED-IN REVENUE		1,729,825			
28	UNBILLED REV - UNCOLLECTIBLE		32,000			
29	UNBILLED REVENUE	-15,748	-1,350,000			0.0857
30	DSM REVENUE-RESIDENTIAL		12,392,225			
31	BLUE SKY REV-RESIDENTIAL		459,753			
32						
33	UTAH					
34	08BLSKY01R-BLUESKY ENERGY		-5			
35	08CFR00001-MTH FACILITY S		838			
36	08CHCK000R-UT RES CHECK M			1		
37	08COOLKPRR -COOL KEEPER			92,428		
38	08LNX00001-MTHLY 80% GUAR		3,171			
39	08LNX00005-MTHLY MIN GUAR		396			
40	08LNX00013-80% MNTHLY MIN		24,144			
41	TOTAL Billed	54,671,093	4,872,459,725	1,812,975	30,155	0.0891
42	Total Unbilled Rev.(See Instr. 6)	-29,881	1,172,000	0	0	-0.0392
43	TOTAL	54,641,212	4,873,631,725	1,812,975	30,139	0.0892

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	08LNX00108-ANN COST MTHLY		2,288			
2	08MHTP0006-MOBILE HOME &	11,456	879,088	8	1,432,000	0.0767
3	08MHTP0023-MOBILE HOME &	109	10,296	1	109,000	0.0945
4	08NETMT135 - NET MTR	23,815	2,778,258	4,479	5,317	0.1167
5	08OALT007R-SECURITY AR LG	2,628	750,468	2,845	924	0.2856
6	08PTLD000R-POST TOP LIGHT	2	131	3	667	0.0655
7	08RESD0001-RES SRVC	6,300,054	698,573,018	724,221	8,699	0.1109
8	08RESD0002-RES SRVC-OPTIO	3,063	333,302	381	8,039	0.1088
9	08RESD0003-LIFELINE PRGRM	194,823	21,217,627	26,343	7,396	0.1089
10	08RGNSV006-GEN SRVC-RES	85,541	6,671,742	229	373,541	0.0780
11	08RGNSV023-GEN SRVC-RES	92,801	10,448,106	12,763	7,271	0.1126
12	08RGNSV06A-UT SM GEN SVC	9,963	847,321	25	398,520	0.0850
13	08RGNSV06B-UT SM GEN SVC	31	2,955	1	31,000	0.0953
14	08RNM06135 - UT NET MTR, GEN	1,015	108,868	6	169,167	0.1073
15	08RNM23135 - UT NET MTR, GEN	243	27,991	40	6,075	0.1152
16	08UPPL000R-BASE SCH FALL			4		
17	REVENUE_ACCT ADJ		-3,226,427			
18	REVENUE ADJ - DEF NPC		19,549,583			
19	SOLAR FEED-IN REVENUE		1,308,320			
20	UNBILLED REV - UNCOLLECTIBLE		35,000			
21	UNBILLED REVENUE	-9,705	-402,000			0.0414
22	DSM REVENUE-RESIDENTIAL		26,999,960			
23	DSM REVENUE-RES GEN SVC		-3			
24	BLUE SKY REV-RESIDENTIAL		1,240,358			
25						
26	WASHINGTON					
27	02LNX00109-REF/NREF ADV +		1,844			
28	02NETMT135 - WA RES NET MTR	3,549	343,232	276	12,859	0.0967
29	02OALTB15R-WA OUTD AR LGT	1,015	152,536	1,097	925	0.1503
30	02RESD0016-WA RES SRVC	1,419,849	131,774,401	99,506	14,269	0.0928
31	02RESD0017-BILL ASSISTANCE	82,974	7,621,617	5,814	14,271	0.0919
32	02RESD0018-WA 3 PHASE RES	2,174	221,685	85	25,576	0.1020
33	02RESD018X-WA 3 PHASE RES	359	35,707	17	21,118	0.0995
34	02RGNSB024-WA SM GEN SVC	21,575	2,507,732	3,465	6,227	0.1162
35	02UPPL000R-BASE SCH FALL			1		
36	REVENUE ADJ - DEF NPC		831,564			
37	REVENUE_ACCT ADJ		-4,225,965			
38	WASHINGTON - CHEHALIS DEF		-1,320,000			
39	UNBILLED REV - UNCOLLECTIBLE		1,000			
40	UNBILLED REVENUE	11,250	1,425,000			0.1267
41	TOTAL Billed	54,671,093	4,872,459,725	1,812,975	30,155	0.0891
42	Total Unbilled Rev.(See Instr. 6)	-29,881	1,172,000	0	0	-0.0392
43	TOTAL	54,641,212	4,873,631,725	1,812,975	30,139	0.0892

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

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1	DSM REVENUE-RESIDENTIAL		4,298,803			
2	BLUE SKY REV-RESIDENTIAL		250,373			
3						
4	WYOMING					
5	05LNX00102-LINE EXT 80% G		768			
6	05NETMT135 - EXP PARTIALREQ	1,379	164,117	136	10,140	0.1190
7	05OALT015R-OUTD AR LGT SR	877	129,812	1,028	853	0.1480
8	05RESD0002-WY RES SRVC	887,505	97,749,577	100,878	8,798	0.1101
9	05RGNSV025-WY SM GEN SVC	9,142	1,115,334	1,419	6,443	0.1220
10	REVENUE ADJ - DEF NPC		132,736			
11	REVENUE_ACCT ADJ		-244,928			
12	UNBILLED REV - UNCOLLECTIBLE		22,000			
13	UNBILLED REVENUE	-14,570	-1,476,000			0.1013
14	DSM REVENUE-RESIDENTIAL		1,515,434			
15	DSM REVENUE-RESIDENTIAL GEN		14,944			
16	BLUE SKY REV-RESIDENTIAL		53,404			
17	05LNX00109-REF/NREF ADV +		850			
18	05RESD0002-WY RES SRVC	113,253	12,681,404	12,494	9,065	0.1120
19	05RGNSV025- SM GEN SVC-RES	396	67,266	127	3,118	0.1699
20	09OALT207R-SECURITY AR LG	71	19,388	87	816	0.2731
21	05NETMT135 - EXP PARTIAL REQ	247	28,928	16	15,438	0.1171
22	09RES00002			2		
23	09RESD0002			4		
24	UNBILLED REVENUE	245	32,000			0.1306
25	DSM REVENUE-RESIDENTIAL		182,510			
26	DSM REVENUE-RES GEN SVC		282			
27	BLUE SKY REV-RESIDENTIAL		19,349			
28						
29	LESS MULTIPLE BILLINGS			-120,170		
30						
31	TOTAL RESIDENTIAL SALES	15,565,510	1,781,722,516	1,574,480	9,886	0.1145
32						
33	COMMERCIAL SALES					
34	CALIFORNIA					
35	06GNSV0025-CA GEN SRVC	51,820	9,096,265	6,433	8,055	0.1755
36	06GNSV025F-GEN SRVC-< 20	963	184,475	85	11,329	0.1916
37	06GNSV0A32-GEN SRVC-20 KW	78,934	12,718,314	1,038	76,044	0.1611
38	06LGSV048T-LRG GEN SERV	28,497	3,031,059	7	4,071,000	0.1064
39	06NMT48135-CA GEN SVC NET	2,525	272,592	1	2,525,000	0.1080
40	06LGSV0A36-LRG GEN SRVC-O	66,160	9,028,658	161	410,932	0.1365
41	TOTAL Billed	54,671,093	4,872,459,725	1,812,975	30,155	0.0891
42	Total Unbilled Rev.(See Instr. 6)	-29,881	1,172,000	0	0	-0.0392
43	TOTAL	54,641,212	4,873,631,725	1,812,975	30,139	0.0892

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

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1	06LNX00102-LINE EXT 80% GTY		5,791			
2	06LNX00105-CNTRCT $ MIN G		4,128			
3	06LNX00109-REF/NREF ADV +		87,569			
4	06LNX00300 - 80% MTHLY MIN		862			
5	06LNX00311 - LINE EXT 80% GTY		15,219			
6	06NMT36135-G SVC NT ->100	2,226	312,999	4	556,500	0.1406
7	06OALT015N-OUTD AR LGT SR	674	198,653	483	1,395	0.2947
8	06RCFL0042-AIRWAY & ATHLE	167	38,786	36	4,639	0.2323
9	06NMT25135-CA GEN SVC NET	66	11,680	9	7,333	0.1770
10	06NMT32135-CA GEN SVC NET	605	108,288	10	60,500	0.1790
11	REVENUE_ACCT ADJ		-1,129,356			
12	06LNX00110-REF/NREF ADV +		5,634			
13	SOLAR FEED-IN REVENUE		33,760			
14	UNBILLED REVENUE	2,623	462,000			0.1761
15	DSM REVENUE-COMMERCIAL		878,057			
16	BLUE SKY REV-COMMERCIAL		1,898			
17						
18	IDAHO					
19	07CISH0019-COMM & IND SPA	4,760	413,362	97	49,072	0.0868
20	07GNSV0006-GEN SRVC-LRG P	223,044	18,345,947	978	228,061	0.0823
21	07GNSV0009-GEN SRVC-HI VO	43,868	2,719,336	2	21,934,000	0.0620
22	07GNSV0023-GEN SRVC-SML P	141,692	14,018,506	6,453	21,958	0.0989
23	07GNSV0035-GEN SRVCOPTION	977	61,548	2	488,500	0.0630
24	07GNSV006A-GEN SRVC-LRG P	24,328	2,139,182	179	135,911	0.0879
25	07GNSV023A-GEN SRVC-SML P	24,446	2,418,161	1,243	19,667	0.0989
26	07GNSV023F-GEN SRVC SML P	7	1,881	5	1,400	0.2687
27	07LNX00010-MNTHLY 80%GUAR		4,459			
28	07LNX00035-ADV 80%MO GUAR		223,961			
29	07LNX00040-ADV+REFCHG+80%		52,383			
30	07OALT007N-SECURITY AR LG	262	102,060	175	1,497	0.3895
31	07OALT07AN-SECURITY AR LG	10	4,059	11	909	0.4059
32	07LNX00312 - ID LINE EXT		20,258			
33	07NMT06135 - NET MTR - LG GEN	1,786	152,518	4	446,500	0.0854
34	07NMT23135 - NET MTR - SM GEN	1,019	89,989	19	53,632	0.0883
35	07LNX00015-ANNUAL 80%GUAR		332			
36	07LNX00311 - LINE EXT 80% GTY		29,576			
37	07LNX00300 - 80% MTHLY MIN		8,144			
38	REVENUE_ACCT ADJ		-35,568			
39	UNBILLED REVENUE	-8,344	-650,000			0.0779
40	DSM REVENUE-COMMERCIAL		849,446			
41	TOTAL Billed	54,671,093	4,872,459,725	1,812,975	30,155	0.0891
42	Total Unbilled Rev.(See Instr. 6)	-29,881	1,172,000	0	0	-0.0392
43	TOTAL	54,641,212	4,873,631,725	1,812,975	30,139	0.0892

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1	DSM REVENUE-SMALL		-6			
2	BLUE SKY REV-COMMERCIAL		1,784	1		
3						
4	OREGON					
5	01COST0023, OR GEN SRV, COST	981,016	56,388,310			0.0575
6	01COST0048 - 01LGSV0048	873,725	42,284,798			0.0484
7	01COST023F - GEN SRV COST	2,939	179,777			0.0612
8	01COSTB023 - OR GEN SRV,	22,721	1,327,737			0.0584
9	01COSTL030 - OR LRG GEN SRV,	1,098,862	56,360,170			0.0513
10	01COSTS028, OR GEN SERV	1,895,331	112,972,531			0.0596
11	01GNSB0023, OR GEN SRV BPA		1,570,484	2,830		
12	01GNSB0028, OR GEN SRV BPA		1,960,233	293		
13	01GNSB023T - OR GEN SRV TOU		30,153	56		
14	01GNSV0023, GEN SRV < 30 KW		52,891,072	55,480		
15	01GNSV0028, GEN SRV > 30 KW		57,075,020	8,831		
16	01GNSV023F - GEN SRV - FLAT RA	10,258	1,623,141	773	13,270	0.1582
17	01GNSV023M - GEN SRV, MANUAL	249	21,839	2	124,500	0.0877
18	01GNSV023T, OR GEN SRV, TOU		169,450	204		
19	01HABT0023, OR HABITAT BLEND	2,443	143,529			0.0588
20	01HABTB023 - OR HABITAT BLEND	24	1,475			0.0615
21	01LGSB0030, GEN DEL SRV, > 200		966,358	21		
22	01LGSV0030 - LG GEN SRV > 1000		28,856,674	621		
23	01LGSV0048-1000KW AND OVR		16,069,546	90		
24	01LGSV048M-LRG GEN SRVC 1	60,396	3,723,758	1	60,396,000	0.0617
25	01LNX00100-LINE EXT 60% G		3,796			
26	01LNX00102-LINE EXT 80% G		468,700			
27	01LNX00103-LINE EXT 80% G		-430			
28	01LNX00105-CNTRCT $ MIN G		14,561			
29	01LNX00109-REF/NREF ADV +		1,060,206			
30	01LNX00110-REF/NREF ADV +		12,798			
31	01LNX00311 - LINE EXT 80% GTY		154,027			
32	01LNX00120 - LINE EXT 60% GTY		24,548			
33	01LNX00300 - LINE EXT 80% GTY		184,844			
34	01LPRS047M-PART REQ SRVC	48,934	4,676,673	5	9,786,800	0.0956
35	01NMT23135 - NET MTR GEN < 30		222,257	256		
36	01NMT28135 - NET MTR GEN > 30		1,035,762	131		
37	01NMT30135 -NET MTR GEN > 200		1,054,653	22		
38	01NMT48135-NET MTR GEN SVC =		410,744	4		
39	01OALT015N-OUTD AR LGT NR	5,546	815,303	2,863	1,937	0.1470
40	01OALTB15N-OUTD AR LGT NR	1,477	246,067	1,076	1,373	0.1666
41	TOTAL Billed	54,671,093	4,872,459,725	1,812,975	30,155	0.0891
42	Total Unbilled Rev.(See Instr. 6)	-29,881	1,172,000	0	0	-0.0392
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1	01PTOU0023, OR GEN SRV, TOU	3,007	174,669			0.0581
2	01PTOUB023, OR GEN SRV, TOU	460	27,768			0.0604
3	01RCFL0054-REC FIELD LGT	1,453	142,946	107	13,579	0.0984
4	01RENW0023, OR RENW USAGE	8,183	478,465			0.0585
5	01RENWB023 - OR RENEWABLE	115	6,752			0.0587
6	01STDAY023 - DAY STD OFR SCH	3,129	175,271			0.0560
7	01STDAY028 - DAY STD OFF SCH	13,194	761,270			0.0577
8	01STDAY030 - STD DAY OFF SCH	4,688	237,075			0.0506
9	01VIR23136-VOL INC <=30KW		147,037	94		
10	01VIR28136-VOL INC >30KW		605,647	91		
11	01VIR30136-VOL INC >200KW		248,895	6		
12	01VIR48136-VOL INC >1000KW		127,899	1		
13	01LGSB0048 - LG GSVC > 1000		82,843	1		
14	01LGSV028M - LGSV, <1000 kW, M	509	45,588	1	509,000	0.0896
15	01GNSV0728 - GEN SVC DIR ACC		193,906	11		
16	01GNSV0730 -GEN SVC DIR ACC		2,137,821	17		
17	01GNSV0748 LG GEN SVC DIR		3,277,155	4		
18	OR GAIN ON SALE OF ASSET		41,184			
19	REVENUE ADJ - DEF NPC		-298,611			
20	REVENUE_ACCT ADJ		-2,503,161			
21	SOLAR FEED-IN REVENUE		1,457,402			
22	UNBILLED REVENUE	9,410	480,000			0.0510
23	DSM REVENUE-COMMERCIAL		8,337,870			
24	BLUE SKY REV-COMMERCIAL		665,521	101		
25						
26	UTAH					
27	08ABL-NRES - APPLICANT BUILT		7,319			
28	08CFR00051-MTH FAC SRVCHG		38,938			
29	08CFR00052-ANN FAC SVCCHG		2			
30	08COOLKPRN - A/C DIRECT LOAD			2,490		
31	08GNSV0006-GEN SRVC-DISTR	4,972,703	418,768,050	11,039	450,467	0.0842
32	08GNSV0009-GEN SRVC-HI VO	816,550	46,401,551	28	29,162,500	0.0568
33	08GNSV0023-GEN SRVC-DISTR	1,200,155	120,139,584	68,359	17,557	0.1001
34	08GNSV006A-GEN SRVC-ENERG	259,386	30,790,016	2,107	123,107	0.1187
35	08GNSV006B-GEN SRVC-DEM&	4,586	502,414	35	131,029	0.1096
36	08GNSV006M-MNL DIST VOLTG	5,298	367,767	6	883,000	0.0694
37	08GNSV009A-GEN SRVC HI VO	25,073	1,694,891	2	12,536,500	0.0676
38	08GNSV023F-GEN SRVC FIXED	1,302	188,034	128	10,172	0.1444
39	08GNSV023M-GNSV DIST VOLT	105	10,012	4	26,250	0.0954
40	08GNSV06AM-MNL ENERGY TOD	346	38,772	1	346,000	0.1121
41	TOTAL Billed	54,671,093	4,872,459,725	1,812,975	30,155	0.0891
42	Total Unbilled Rev.(See Instr. 6)	-29,881	1,172,000	0	0	-0.0392
43	TOTAL	54,641,212	4,873,631,725	1,812,975	30,139	0.0892

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

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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	08GNSV06MN-GNSV DIST VOLT	38,748	2,992,465	599	64,688	0.0772
2	08LNX00002-MTHLY 80% GUAR		266,853			
3	08LNX00004-ANNUAL 80%GUAR		30,322			
4	08LNX00006-FIXD MTHLY MIN		3,518			
5	08LNX00008-ANNUALMIN GUAR		-13,225			
6	08LNX00014-80% MIN MNTHLY		1,487,683			
7	08LNX00017-ADV/REF&80%ANN		140,416			
8	08LNX00158-ANNUALCOST MTH		32,125			
9	08LNX00300 - LINE EXT 80% PLUS		125,689			
10	08LNX00310 - IRR 80% ANN MIN		40,766			
11	08LNX00312 UT IRG LINE EXT		5,426			
12	08NMT06135-NET MTR GEN SV	76,343	6,684,427	156	489,378	0.0876
13	08NMT08135 -NET MTR GEN SVC	60,428	4,254,024	7	8,632,571	0.0704
14	08NMT23135 - UT NET MTR, GEN	4,228	452,354	279	15,154	0.1070
15	08NMT6A135-NET MTR GEN SVC T	2,518	318,243	19	132,526	0.1264
16	08OALT007N-SECURITY AR LG	7,936	1,846,662	4,199	1,890	0.2327
17	08POLE0075-POLES W/LIGHT		226	2		
18	08PRSV031M-BKUP MNT&SUPPL	48,403	3,422,745	4	12,100,750	0.0707
19	08PTLD000N-POST TOP LIGHT	6	454	2	3,000	0.0757
20	08TOSS015F-TRAFFIC SIG NM	171	15,948	20	8,550	0.0933
21	08TOSS0015-TRAF & OTHER S	2,580	277,989	920	2,804	0.1077
22	08MONL0015-MTR OUTDONIGHT	17,436	1,234,321	472	36,941	0.0708
23	REVENUE_ACCT ADJ		-2,461,536			
24	REVENUE ADJ - DEF NPC		20,304,110			
25	SOLAR FEED-IN REVENUE		909,627			
26	08LNX00311 - LINE EXT 80% GTY		285,206			
27	08GNSV0008 -GEN SVC TOU	936,151	69,959,661	135	6,934,452	0.0747
28	08GNSV008M -GEN SVC TOU	25,456	2,007,322	4	6,364,000	0.0789
29	UNBILLED REVENUE	22,744	1,443,000			0.0634
30	DSM REVENUE-COMMERCIAL		26,097,272			
31	DSM REVENUE-SMALL		-1,166			
32	BLUE SKY REV-COMMERCIAL		241,224			
33						
34	WASHINGTON					
35	02GNSB0024-WA GEN SRVC DO	28,750	2,741,664	1,469	19,571	0.0954
36	02GNSB024F-GEN SRVC DOM/F	154	19,561	6	25,667	0.1270
37	02GNSB24FP-WA GEN SVC	291	101,226	81	3,593	0.3479
38	02GNSV0024-WA GEN SRVC	473,916	43,218,596	13,654	34,709	0.0912
39	02GNSV024F-WA GEN SRVC-FL	1,099	149,870	109	10,083	0.1364
40	02LGSB0036-LRG GEN SVC IRG	60,856	4,907,262	103	590,835	0.0806
41	TOTAL Billed	54,671,093	4,872,459,725	1,812,975	30,155	0.0891
42	Total Unbilled Rev.(See Instr. 6)	-29,881	1,172,000	0	0	-0.0392
43	TOTAL	54,641,212	4,873,631,725	1,812,975	30,139	0.0892

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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	02LGSV0036-WA LRG GEN SRV	776,739	60,716,930	874	888,717	0.0782
2	02LGSV048T-LRG GEN SRVC 1	194,218	13,786,152	34	5,712,294	0.0710
3	02LNX00102-LINE EXT 80% G		28,755			
4	02LNX00103-LINE EXT 80% G		20			
5	02LNX00105-CNTRCT $ MIN G		1,726			
6	02LNX00109-REF/NREF ADV +		244,743			
7	02LNX00110-REF/NREF ADV +		38,999			
8	02LNX00112-YR INCURRED CH		669			
9	02LNX00300-LINE EXT 80% G		7,699			
10	02LNX00310 - IRG, 80% ANNUAL		983			
11	02LNX00311 - LINE EXT 80% GTY		59,787			
12	02LNX00312 - WA IRG LINE EXT		3,818			
13	02OALT015N-WA OUTD AR LGT	1,510	211,625	799	1,890	0.1401
14	02OALTB15N-WA OUTD AR LGT	537	82,212	485	1,107	0.1531
15	02RCFL0054-WA REC FIELD L	263	24,168	29	9,069	0.0919
16	02NMT24135, NET MTR, WA	1,937	173,345	42	46,119	0.0895
17	02NMT36135-NET METER LG SVC	5,399	446,767	8	674,875	0.0828
18	02NMT48135-WA LG SVC NET	6,974	490,955	1	6,974,000	0.0704
19	REVENUE ADJ - DEF NPC		793,685			
20	REVENUE_ACCT ADJ		-3,939,277			
21	WASHINGTON - CHEHALIS DEF		-1,020,000			
22	UNBILLED REVENUE	9,607	1,018,000			0.1060
23	DSM REVENUE-COMMERCIAL		3,997,645			
24	BLUE SKY REV-COMMERCIAL		68,831	5		
25						
26	WYOMING					
27	05CHCK000N-WY NRES CHECK			1		
28	05GNSV0025-WY GEN SRVC	227,110	22,538,106	17,546	12,944	0.0992
29	05GNSV0028-GEN SVC > 15 KW	891,781	77,064,076	3,360	265,411	0.0864
30	05GNSV025F-GEN SRVC-FL RA	1,011	162,647	179	5,648	0.1609
31	05LGSV0046-WY LRG GEN SRV	158,332	11,962,592	18	8,796,222	0.0756
32	05LGSV048T-LRG GENSRV TIM	12,362	961,948	1	12,362,000	0.0778
33	05LNX00100-LINE EXT 60% G		342			
34	05LNX00102-LINE EXT 80% G		662,980			
35	05LNX00103-LINE EXT 80% G		1,857			
36	05LNX00105-CNTRCT $ MIN G		5,417			
37	05LNX00109-REF/NREF ADV +		595,567			
38	05LNX00110-REF/NREF ADV +		6,321			
39	05LNX00114-TEMP SVC 12MO>		1,401			
40	05NMT25135 - NET MTR, GEN	213	22,817	24	8,875	0.1071
41	TOTAL Billed	54,671,093	4,872,459,725	1,812,975	30,155	0.0891
42	Total Unbilled Rev.(See Instr. 6)	-29,881	1,172,000	0	0	-0.0392
43	TOTAL	54,641,212	4,873,631,725	1,812,975	30,139	0.0892

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1	05NMT28135-NET MTR SM GEN	6,411	413,693	18	356,167	0.0645
2	05OALT015N-OUTD AR LGT SR	2,698	402,922	1,654	1,631	0.1493
3	05RCFL0054-WY REC FIELD L	803	61,615	54	14,870	0.0767
4	05LNX00300 - LINE EXT 80% GTY		77,935			
5	05LNX00311 - LINE EXT 80% GTY		85,546			
6	05LNX00312 - WY IRG LINE EXT		5,094			
7	REVENUE ADJ - DEF NPC		190,004			
8	REVENUE_ACCT ADJ		-314,963			
9	UNBILLED REVENUE	4,726	469,000			0.0992
10	DSM REVENUE-SMALL		1,409,918			
11	DSM REVENUE-LARGE		65,920			
12	BLUE SKY REV-COMMERCIAL		3,289			
13	05GNSV0025-WY GEN SRVC	31,090	3,076,186	2,356	13,196	0.0989
14	05GNSV0028-GEN SVC > 15 KW	92,873	8,038,500	395	235,122	0.0866
15	05GNSV025F-GEN SRVC-FL RA	199	25,404	33	6,030	0.1277
16	05LNX00102-LINE EXT 80% G		2,063			
17	05LNX00109-REF/NREF ADV +		215,111			
18	05LNX00110-REF/NREF ADV +		1,806			
19	05LNX00114-TEMP SVC 12MO>		488			
20	05NMT25135 - WY NET MTR, GEN	27	2,294	3	9,000	0.0850
21	05NMT28135-NET MTR SM GEN	515	37,019	3	171,667	0.0719
22	09OALT207N-SECURITY AR LG	273	64,804	137	1,993	0.2374
23	09MONL0213-WY MTR OUTDOOR	368	23,021	11	33,455	0.0626
24	05LNX00300 - LINE EXT 80%		7,815			
25	05LNX00311 - LINE EXT 80%		6,076			
26	UNBILLED REVENUE	-985	-91,000			0.0924
27	DSM REVENUE-SMALL		39,922			
28	BLUE SKY REV-COMMERCIAL		740			
29						
30	LESS MULTIPLE BILLINGS			-24,247		
31						
32	TOTAL COMMERCIAL SALES	17,261,893	1,556,424,635	201,691	85,586	0.0902
33						
34	INDUSTRIAL SALES					
35	CALIFORNIA					
36	06GNSV0025-CA GEN SRVC	642	115,692	90	7,133	0.1802
37	06GNSV0A32-GEN SRVC-20 KW	2,709	459,045	21	129,000	0.1695
38	06LGSV048T-LRG GEN SERV	49,537	5,510,842	9	5,504,111	0.1112
39	06LGSV0A36-LRG GEN SRVC-O	4,825	706,647	12	402,083	0.1465
40	REVENUE_ACCT ADJ		-212,425			
41	TOTAL Billed	54,671,093	4,872,459,725	1,812,975	30,155	0.0891
42	Total Unbilled Rev.(See Instr. 6)	-29,881	1,172,000	0	0	-0.0392
43	TOTAL	54,641,212	4,873,631,725	1,812,975	30,139	0.0892

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1	SOLAR FEED-IN REVENUE		6,435			
2	UNBILLED REVENUE	-370	-5,000			0.0135
3	DSM REVENUE-INDUSTRIAL		163,191			
4	BLUE SKY REV-INDUSTRIAL		19			
5						
6	IDAHO					
7	07CFR00001-MTH FACILITY S		2,217			
8	07CISH0019-COMM & IND SPA	44	4,237	2	22,000	0.0963
9	07GNSV0006-GEN SRVC-LRG P	93,755	6,743,535	107	876,215	0.0719
10	07GNSV0009-GEN SRVC-HI VO	80,119	5,117,244	16	5,007,438	0.0639
11	07GNSV0023-GEN SRVC-SML P	12,511	1,194,663	319	39,219	0.0955
12	07GNSV0035-GEN SRVCOPTION	935	64,824	1	935,000	0.0693
13	07GNSV006A-GEN SRVC LG P	3,337	277,364	22	151,682	0.0831
14	07GNSV023A-GEN SRVC-SML P	2,027	210,865	147	13,789	0.1040
15	07GNSV023S-IDAHO TRAFFIC	5	649	1	5,000	0.1298
16	07LNX00010-MNTHLY 80%GUAR		4,113			
17	07LNX00108-ANN COST MTHLY		1,996			
18	07OALT007N-SECURITY AR LG	13	5,035	16	813	0.3873
19	07OALT07AN-SECURITY AR LG		238	1		
20	07SPCL0001	1,456,100	93,499,403	1	1,456,100,000	0.0642
21	07SPCL0002	115,559	7,156,495	1	115,559,000	0.0619
22	REVENUE_ACCT ADJ		-12,517			
23	UNBILLED REVENUE	-45,553	-2,062,000			0.0453
24	DSM REVENUE-INDUSTRIAL		285,972			
25						
26	OREGON					
27	01COST0023, GEN SRV CST BSD	19,006	1,093,503			0.0575
28	01COST0048 - 01LGSV0048	1,696,132	81,316,696			0.0479
29	01COST023F - GEN SRV CST-BSD	1	63			0.0630
30	01COSTB023 - GEN SRV, CST-BSD	271	14,482			0.0534
31	01COSTL030 - LRG GEN SRV, CST	213,245	10,970,134			0.0514
32	01COSTS028, OR GEN SERV	89,486	5,322,250			0.0595
33	01GNSB0023, OR GEN SRV, BPA		15,813	14		
34	01GNSB0028, OR GEN SRV, BPA		3,447	1		
35	01GNSV0023, OR GEN SRV, < 30		1,071,537	1,014		
36	01GNSV0028, OR GEN SRV > 30		3,508,181	445		
37	01GNSV023F - GEN SRV - FLT	2	652	2	1,000	0.3260
38	01GNSV023M - OR GEN SRV	19	2,239	1	19,000	0.1178
39	01GNSV023T, GEN SRV, TOU OPT		2,484	3		
40	01GNSV0730 -GEN SVC DIR		45,076	1		
41	TOTAL Billed	54,671,093	4,872,459,725	1,812,975	30,155	0.0891
42	Total Unbilled Rev.(See Instr. 6)	-29,881	1,172,000	0	0	-0.0392
43	TOTAL	54,641,212	4,873,631,725	1,812,975	30,139	0.0892

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1	01GNSV0748 LG GEN SVC DIR		1,784,307	3		
2	01LGSV0030 - LG G SRV > 1000		7,952,909	146		
3	01LGSV0048-1000KW AND OVR		29,430,856	86		
4	01LGSV048M-LRG GEN SRVC 1	76,782	5,997,485	3	25,594,000	0.0781
5	01LNX00102-LINE EXT 80% G		53,545			
6	01LNX00109-REF/NREF ADV +		6,156			
7	01LNX00300 - LINE EXT 80% GTY		21,298			
8	01LPRS047M-PART REQ SRVC	18,999	2,158,568	2	9,499,500	0.1136
9	01NMT23135 - NET MTR GEN < 30		1,671	3		
10	01NMT28135 - NET MTR GEN > 30		43,729	5		
11	01NMT30135 - NET MTR GEN > 200		46,862	1		
12	01OALT015N-OUTD AR LGT NR	289	41,350	127	2,276	0.1431
13	01OALTB15N-OR OUTD AR LGT	4	545	4	1,000	0.1363
14	01PTOU0023, GEN SRV, TOU ENG	34	2,198			0.0646
15	01RENW0023, RENW USAGE SPLY	83	4,631			0.0558
16	01STDAY028 - DAY STD OFF SCH	233	13,765			0.0591
17	01STDAY030 - STD DAY OFF SCH	1,913	88,804			0.0464
18	01VIR23136-VOL INC <=30KW		931	1		
19	01VIR28136-VOL INC >30 KW		4,686	2		
20	01VIR30136-VOL INC >200KW		36,569	1		
21	OR GAIN ON SALE OF ASSET		28,463			
22	REVENUE ADJ - DEF NPC		-98,687			
23	REVENUE_ACCT ADJ		-1,691,150			
24	SOLAR FEED-IN REVENUE		967,544			
25	UNBILLED REVENUE	5,023	448,000			0.0892
26	DSM REVENUE-INDUSTRIAL		760,093			
27	BLUE SKY REV-INDUSTRIAL		465,699	34		
28						
29	UTAH					
30	08CFR00051-MTH FAC SRVCHG		18,725			
31	08EFOP0021-ELEC FURNACE O	1,700	188,561	2	850,000	0.1109
32	08EFOP021M-ELEC FURNACE O	976	153,097	3	325,333	0.1569
33	08GNSV0006-GEN SRVC-DISTR	655,316	57,457,754	1,078	607,900	0.0877
34	08GNSV0009-GEN SRVC-HI VO	3,286,865	182,968,734	114	28,832,149	0.0557
35	08GNSV0023-GEN SRVC-DISTR	53,605	5,459,776	3,332	16,088	0.1019
36	08GNSV006A-GEN SRVC-ENERG	63,064	7,480,089	258	244,434	0.1186
37	08GNSV006B-GEN SRVC-DEM&	221	21,530	1	221,000	0.0974
38	08GNSV009A-GEN SRVC HI VO	15,585	1,403,212	6	2,597,500	0.0900
39	08GNSV009M-MANL HIGH VOLT	495,488	27,448,075	10	49,548,800	0.0554
40	08GNSV023F-GEN SRVC FIXED	4	2,572	1	4,000	0.6430
41	TOTAL Billed	54,671,093	4,872,459,725	1,812,975	30,155	0.0891
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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	08GNSV06MN-GNSV DIST VOLT	1,231	106,067	23	53,522	0.0862
2	08GNSV09AM-MAN TOD HIVOLT	1,171	139,288	1	1,171,000	0.1189
3	08LNX00002-MTHLY 80% GUAR		565,912			
4	08LNX00014-80% MIN MNTHLY		9,731			
5	08LNX00311 - LINE EXT 80% GTY		2,016			
6	08LNX00300 - LINE EXT 80% PLUS		44,988			
7	08LNX00310 - IRR 80% ANN MIN		8,942			
8	08OALT007N-SECURITY AR LG	1,181	253,942	447	2,642	0.2150
9	08TOSS0015-TRAF & OTHER S	8	1,310	9	889	0.1638
10	08MONL0015-MTR OUTDONIGHT	14	2,902	7	2,000	0.2073
11	08NMT06135-NET MTR GEN SV	2,802	313,425	7	400,286	0.1119
12	08NMT23135 -NET MTR G <25	240	22,635	11	21,818	0.0943
13	08NMT6A135-NET MTR GEN SVC T	3,589	465,460	8	448,625	0.1297
14	08PRSV031M-BKUP MNT&SUPPL	4,775	714,887	1	4,775,000	0.1497
15	08SPCL0001	571,512	28,502,759	1	571,512,000	0.0499
16	08SPCL0002	962,388	44,043,605	1	962,388,000	0.0458
17	08SPCL0003	1,163,268	55,169,764	1	1,163,268,000	0.0474
18	REVENUE_ACCT ADJ		-2,652,805			
19	REVENUE ADJ - DEF NPC		12,544,010			
20	08GNSV06AM-MNL ENERGY TOD	269	34,348	2	134,500	0.1277
21	08GNSV0008 - GEN SVC TOU	964,487	73,140,060	99	9,742,293	0.0758
22	08GNSV008M - GEN SVC TOU	60,925	4,626,756	7	8,703,571	0.0759
23	SOLAR FEED-IN REVENUE		1,134,451			
24	UNBILLED REVENUE	13,332	1,299,000			0.0974
25	DSM REVENUE-INDUSTRIAL		13,334,672			
26	DSM REVENUE-SMALL		-3,095			
27	BLUE SKY REV-INDUSTRIAL		61,442	7		
28						
29	WASHINGTON					
30	02GNSB0024-WA GEN SRVC DO	1,233	128,835	48	25,688	0.1045
31	02GNSB24FP-WA GEN SVC	4	1,741	1	4,000	0.4353
32	02GNSV0024-WA GEN SRVC	16,067	1,479,221	336	47,818	0.0921
33	02GNSV024F-WA GEN SRVC-FL	33	8,401	4	8,250	0.2546
34	02LGSV0036-WA LRG GEN SRV	102,598	8,298,368	101	1,015,822	0.0809
35	02LGSV048T-LRG GEN SRVC 1	665,108	41,928,936	31	21,455,097	0.0630
36	02OALT015N-WA OUTD AR LGT	106	13,814	39	2,718	0.1303
37	02OALTB15N-WA OUTD AR LGT	26	3,921	14	1,857	0.1508
38	02PRSV47TM-LRG PART REQMT	2,386	332,339	1	2,386,000	0.1393
39	02LGSB0036-LRG GEN SVC IRG	1,836	214,506	11	166,909	0.1168
40	REVENUE ADJ - DEF NPC		428,559			
41	TOTAL Billed	54,671,093	4,872,459,725	1,812,975	30,155	0.0891
42	Total Unbilled Rev.(See Instr. 6)	-29,881	1,172,000	0	0	-0.0392
43	TOTAL	54,641,212	4,873,631,725	1,812,975	30,139	0.0892

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1	REVENUE_ACCT ADJ		-1,601,642			
2	WASHINGTON - CHEHALIS DEF		-510,000			
3	UNBILLED REVENUE	4,777	508,000			0.1063
4	DSM REVENUE-INDUSTRIAL		1,626,843			
5						
6	WYOMING					
7	05GNSV0025-WY GEN SRVC	27,017	2,426,201	1,165	23,191	0.0898
8	05GNSV0028-GEN SVC > 15 KW	267,032	20,094,302	483	552,861	0.0753
9	05GNSV025F-GEN SRVC-FL RA	26	4,302	8	3,250	0.1655
10	05LGSV0046-WY LRG GEN SRV	1,679,461	114,155,865	58	28,956,224	0.0680
11	05LGSV046M-WY LRG GEN SRV	12,283	873,310	1	12,283,000	0.0711
12	05LGSV048M-TOU>1000KW MAN	298,416	17,096,596	1	298,416,000	0.0573
13	05LGSV048T-LRG GENSRV TIM	1,682,423	99,360,650	11	152,947,545	0.0591
14	05LNX00100-LINE EXT 60% G		46,228			
15	05LNX00102-LINE EXT 80% G		1,011,109			
16	05LNX00103-LINE EXT 80% G		7,266			
17	05LNX00105-CNTRCT $ MIN G		40,585			
18	05LNX00109-REF/NREF ADV +		337,944			
19	05LNX00110-REF/NREF ADV +		263			
20	05LNX00300 - LINE EXT 80%		24,537			
21	05LNX00311 - LINE EXT 80%		32,249			
22	05OALT015N-OUTD AR LGT SR	80	10,763	40	2,000	0.1345
23	05PRSV033M-PART SERV REQ	1,220,084	84,334,311	8	152,510,500	0.0691
24	REVENUE ADJ - DEF NPC		890,567			
25	REVENUE_ACCT ADJ		-1,216,183			
26	UNBILLED REVENUE	-14,881	-581,000			0.0390
27	DSM REVENUE-SMALL		346,413			
28	DSM REVENUE-LARGE		1,654,360			
29	BLUE SKY REV-INDUSTRIAL		-5,656			
30	05GNSV0025-WY GEN SRVC	3,837	382,103	290	13,231	0.0996
31	05GNSV0028-GEN SVC > 15 KW	54,750	4,145,832	75	730,000	0.0757
32	05GNSV028M-GEN SVC > 15 KW	4,106	257,029	3	1,368,667	0.0626
33	05LGSV0046-WY LRG GEN SRV	45,268	3,329,116	4	11,317,000	0.0735
34	05LGSV048M-TOU>1000KW MAN	221,775	13,320,751	4	55,443,750	0.0601
35	05LGSV048T-LRG GENSRV TIM	1,273,793	79,202,675	12	106,149,417	0.0622
36	05LNX00102-LINE EXT 80% G		47,889			
37	05LNX00109-REF/NREF ADV +		2,224,768			
38	05LNX00300 - LINE EXT 80%		1,915			
39	05PRSV033M-PART SERV REQ	94,170	6,078,162	2	47,085,000	0.0645
40	09OALT207N-SECURITY AR LG	5	986	3	1,667	0.1972
41	TOTAL Billed	54,671,093	4,872,459,725	1,812,975	30,155	0.0891
42	Total Unbilled Rev.(See Instr. 6)	-29,881	1,172,000	0	0	-0.0392
43	TOTAL	54,641,212	4,873,631,725	1,812,975	30,139	0.0892

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1	UNBILLED REVENUE	-3,008	-211,000			0.0701
2	DSM REVENUE-SMALL		19,326			
3	DSM REVENUE-LARGE		408,691			
4	BLUE SKY REV-INDUSTRIAL		14			
5						
6	LESS MULTIPLE BILLINGS			-945		
7						
8	TOTAL INDUSTRIAL SALES	19,882,544	1,290,679,841	9,911	2,006,109	0.0649
9						
10	IRRIGATION SALES					
11	CALIFORNIA					
12	06APSV0020-AG PMP SRVC	11,967	1,704,024	769	15,562	0.1424
13	06APSV020L-AG PMP SRVC-NO	56,843	8,493,671	602	94,424	0.1494
14	06LGSV048T-LRG GEN SERV	976	136,687	1	976,000	0.1400
15	06LNX00103-LINE EXT 80% G		2,363			
16	06LNX00109-REF/NREF ADV +		505			
17	06LNX00110-REF/NREF ADV +		24,769			
18	06LNX00310-80% ANN MIN + 80%		2,439			
19	06LNX00312 - CA IRG LINE EXT		12,053			
20	06NML20135-AGRI PUMP-NET MTR	343	73,809	7	49,000	0.2152
21	06NMT20135-AGRI PUMP-NET	56	9,746	1	56,000	0.1740
22	06USBR0020-KLAM IRG ONPRJ	3,047	535,953	278	10,960	0.1759
23	06USBR020L-KLAM IRG PRJ-NO	19,832	3,276,173	373	53,169	0.1652
24	SOLAR FEED-IN REVENUE		10,106			
25	UNBILLED REVENUE	12	3,000			0.2500
26	DSM REVENUE-IRRIGATION		335,180			
27	BLUE SKY REV-IRRIGATION		23			
28	REVENUE_ACCT ADJ		-434,910			
29						
30	IDAHO					
31	07APSA010L - IRG & PUMP LG	381,201	35,666,439	2,690	141,710	0.0936
32	07APSA010S - IRG & PUMP SM	4,928	556,937	351	14,040	0.1130
33	07APSAL10X - IRG & PUMP - LG	188,997	17,534,870	1,451	130,253	0.0928
34	07APSAS10X - IRG & PUMP - SM	6,474	696,420	396	16,348	0.1076
35	07APSV006A-LRG POWER OPT	1,751	138,724	2	875,500	0.0792
36	07APSV023A-SM POWER OPT S	477	46,794	4	119,250	0.0981
37	07APSVCNLL-LG LOAD CANAL	19,779	1,636,272	46	429,978	0.0827
38	07APSVCNLS-SM LOAD CANAL	38	5,926	12	3,167	0.1559
39	07LNX00015-ANNUAL 80%GUAR		445			
40	07LNX00035-ADV 80%MO GUAR		1,516			
41	TOTAL Billed	54,671,093	4,872,459,725	1,812,975	30,155	0.0891
42	Total Unbilled Rev.(See Instr. 6)	-29,881	1,172,000	0	0	-0.0392
43	TOTAL	54,641,212	4,873,631,725	1,812,975	30,139	0.0892

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1	07LNX00040-ADV+REFCHG+80%		159,528			
2	07LNX00310 80% ANNUAL GTY		1,485			
3	07LNX00311 - LINE EXT 80% GTY		1,648			
4	07LNX00312 - ID LINE EXT		55,276			
5	07APSN010L - ID LG IRR & PUMP	3,033	300,569	30	101,100	0.0991
6	07APSN010S - IRRIGATION SM	200	19,954	5	40,000	0.0998
7	07APSNS10X - IRRIGATION SM	213	24,160	15	14,200	0.1134
8	REVENUE_ACCT ADJ		-43,506			
9	UNBILLED REVENUE	-3	-5,000			1.6667
10	DSM REVENUE-IRRIGATION		1,190,211			
11	BLUE SKY REV-IRRIGATION		74	3		
12						
13	OREGON					
14	01APSV0041-AG PMP SRVC		1,874,099	3,137		
15	01APSV0215-OR IRR TOU PILO		22,972	6		
16	01APSV041L-PUMP SERV >30KW		3,019,301	837		
17	01APSV041T - AGR PUMP SRV		31,759	60		
18	01APSV041X-AG PMP SRVC		958,622	1,812		
19	01APSV41XL-OR Pumping Serv		1,542,226	322		
20	01COST0041 -01APSV0041	149,477	8,704,806			0.0582
21	01COST0048 - 01LGSV0048	127,359	6,251,514			0.0491
22	01COST0215-OR TOU PILOT COST	6,975	286,371			0.0411
23	01COSTS028 G SERV CST > 30	612	36,407			0.0595
24	01CSTUSB41-USBR IRR CONTRA	69,254	4,032,271			0.0582
25	01GNSB0028-OR GENL SVC > 30		7,780	1		
26	01GNSV0028, OR GEN SRV > 30		16,794	2		
27	01HABIT041 - 01APSV0041 AG	9	506			0.0562
28	01LGSB0048 - LG GEN SVC > 1000		1,184,487	3		
29	01LGSV0030-3P,DEMAND,VAR,SE			1		
30	01LGSV0048-1000KW AND OVR		1,477,323	3		
31	01LNX00103-LINE EXT 80% G		42,167			
32	01LNX00110-REF/NREF ADV +		200,360			
33	01LNX00310-LINE EXTENSION		16,341			
34	01PTOU0041 - 01APSV0041 AG	609	35,027			0.0575
35	01RENEW041 - 01APSV0041 AG	182	10,576			0.0581
36	01STDAY041 - DAILY STD OFFER	158	9,539			0.0604
37	01USBR0215-OR IRG TOU PILOT		239,708	54		
38	01USBRGV41-IRG TOU W/O BPA		36,513	9		
39	01USBROF41-KLAMATH BASIN		1,574,072	511		
40	01USBRON41-KLAMATH BASIN	-15	1,596,289	1,176	-13	-106.4193
41	TOTAL Billed	54,671,093	4,872,459,725	1,812,975	30,155	0.0891
42	Total Unbilled Rev.(See Instr. 6)	-29,881	1,172,000	0	0	-0.0392
43	TOTAL	54,641,212	4,873,631,725	1,812,975	30,139	0.0892

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1	01VIR41136-OR VOLUME INC		45,393	17		
2	01VRU41136-VOL INC USB		310,208	87		
3	01VRU41215-VOL INC USB TOU		59,367	7		
4	SOLAR FEED-IN REVENUE		34,420			
5	UNBILLED REVENUE	188	8,000			0.0426
6	DSM REVENUE-IRRIGATION		522,065			
7	BLUE SKY REV-IRRIGATION		414			
8	01LNX00312 - OR IRG LINE EXT		28,896			
9	01NMT41135 - NETMTR AG PMP		6,706	9		
10	01NMT41215-NET MTR APSV TOU		6,764	1		
11	01NMU41135 -NET MTR <PRJ		30,447	6		
12	01NMU41215-IRG TOU PILOT		-49			
13	OR GAIN ON SALE OF ASSET		2,148			
14	REVENUE ADJ - DEF NPC		1,466			
15	REVENUE_ACCT ADJ		-93,583			
16						
17	UTAH					
18	08APSV0010-IRR & SOIL DRA	206,918	15,804,068	2,886	71,697	0.0764
19	08APSV10NS- LG SOIL DRAIN	35,060	2,484,994	226	155,133	0.0709
20	08LNX00004-ANNUAL 80%GUAR		4,179			
21	08LNX00014-80% MIN MNTHLY		16,940			
22	08LNX00017-ADV/REF&80%ANN		196,401			
23	08LNX00310 - IRR, 80% ANN MIN		9,462			
24	08LNX00311 - LINE EXT 80% GTY		356			
25	08LNX00312 UT IRG LINE EXT		24,443			
26	08NMT10135-UT IRR_SOIL DRNG	1,392	114,287	14	99,429	0.0821
27	REVENUE_ACCT ADJ		-66,570			
28	SOLAR FEED-IN REVENUE		26,511			
29	UNBILLED REVENUE	-21	3,000			-0.1429
30	DSM REVENUE-IRRIGATION		688,421			
31						
32	WASHINGTON					
33	02APSV0040-WA AG PMP SRVC	141,779	12,053,742	3,364	42,146	0.0850
34	02APSV040X-WA AG PMP SRVC	56,949	4,901,310	1,835	31,035	0.0861
35	02LNX00103-LINE EXT 80% G		6,190			
36	02LNX00105-CNTRCT $ MIN G		86			
37	02LNX00109-REF/NREF ADV +		8,130			
38	02LNX00110-REF/NREF ADV +		149,167			
39	02LNX00310 - IRG 80% ANN MIN		7,772			
40	02LNX00311 - LINE EXT 80%		190			
41	TOTAL Billed	54,671,093	4,872,459,725	1,812,975	30,155	0.0891
42	Total Unbilled Rev.(See Instr. 6)	-29,881	1,172,000	0	0	-0.0392
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1	02LNX00312 - WA IRG LINE EXT		41,031			
2	02NMT40135-WA NET MTR -IRG	56	4,993	3	18,667	0.0892
3	REVENUE ADJ - DEF NPC		87,146			
4	REVENUE_ACCT ADJ		-553,377			
5	WASHINGTON - CHEHALIS DEF		-120,000			
6	UNBILLED REVENUE	173	-6,000			-0.0347
7	DSM REVENUE-IRRIGATION		558,905			
8	BLUE SKY REV-IRRIGATION		199	7		
9						
10	WYOMING					
11	05APS00040-AG PUMPING SVC	17,235	1,538,410	684	25,197	0.0893
12	05APSNS040-AG PUMPING SVC -	1,055	87,819	15	70,333	0.0832
13	05LNX00103-LINE EXT 80% G		6,838			
14	05LNX00109-REF/NREF ADV +		1,339			
15	05LNX00110-REF/NREF ADV +		53,904			
16	05LNX00310-LINE EXTCONTRAC		945			
17	05LNX00312 - WY IRG LINE EXT		9,566			
18	UNBILLED REVENUE	-2	-3,000			1.5000
19	REVENUE_ACCT ADJ		-2,524			
20	DSM REVENUE-IRRIGATION		12,663			
21	05APS00040-AG PUMPING SVC	134	9,279	1	134,000	0.0692
22	05LNX00110-REF/NREF ADV +		20,269			
23	05LNX00312 - WY IRG LINE EXT		1,017			
24	09APSNS210-IRR & SOIL DRA -	223	22,970	2	111,500	0.1030
25	09APSV0210-IRR & SOIL DRA	4,191	377,453	89	47,090	0.0901
26	DSM REVENUE-IRRIGATION		1,081			
27						
28	LESS MULTIPLE BILLINGS			-829		
29						
30	TOTAL IRRIGATION SALES	1,520,114	144,928,830	23,394	64,979	0.0953
31						
32	PUBLIC STREET & HWY LIGHTING					
33	CALIFORNIA					
34	06CUSL053E-SPECIAL CUST O	1,273	231,290	109	11,679	0.1817
35	06CUSL058F-CUST OWND STR	188	37,946	22	8,545	0.2018
36	06HPSV0051-HI PRESSURE SO	680	223,338	78	8,718	0.3284
37	DSM REVENUE-PUB ST & HWY LT		12,475			
38	REVENUE_ACCT ADJ		-15,969			
39	SOLAR FEED-IN REVENUE		483			
40	UNBILLED REVENUE	137	33,000			0.2409
41	TOTAL Billed	54,671,093	4,872,459,725	1,812,975	30,155	0.0891
42	Total Unbilled Rev.(See Instr. 6)	-29,881	1,172,000	0	0	-0.0392
43	TOTAL	54,641,212	4,873,631,725	1,812,975	30,139	0.0892

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

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						
2	IDAHO					
3	07GNSV023S-IDAHO TRAFFIC	142	17,423	24	5,917	0.1227
4	07SLCO0011-STR LGT CO-OWN	101	46,784	44	2,295	0.4632
5	07SLCU012E-ENGY STR LGT	362	40,374	28	12,929	0.1115
6	07SLCU012F-FULL MNT STR	1,867	370,974	190	9,826	0.1987
7	07SLCU012P-PART MNT STR LGT	194	28,110	16	12,125	0.1449
8	REVENUE_ACCT ADJ		-611			
9	DSM REVENUE-PUB ST & HWY LT		10,576			
10	UNBILLED REVENUE	-3	-1,000			0.3333
11						
12	OREGON					
13	01COSL0052-STR LGT SRVC C	390	58,933	35	11,143	0.1511
14	01CUSL0053-CUS-OWNED MTRD	743	55,249	73	10,178	0.0744
15	01CUSL053E-STR LGT SVC	8,831	642,775	176	50,176	0.0728
16	01CUSL053F-STR LGT SRVC C	124	11,838	9	13,778	0.0955
17	01HPSV0051-HI PRESSURE SO	19,660	4,147,163	741	26,532	0.2109
18	01LEDSL051-OR LED PILOT	119	41,321	34	3,500	0.3472
19	01MVSL0050-MERC VAPSTR LG	7,587	1,006,048	236	32,148	0.1326
20	01OALT015N-OUTD AR LGT NR	2	365	3	667	0.1825
21	01OALTB15N-OR OUTD AR LGT	4	603	2	2,000	0.1508
22	DSM REVENUE-PUB ST & HWY LT		123,541			
23	OR GAIN ON SALE OF ASSET		354			
24	REVENUE ADJ - DEF NPC		349			
25	REVENUE_ACCT ADJ		-17,425			
26	SOLAR FEED-IN REVENUE		8,395			
27	UNBILLED REVENUE	7	3,000			0.4286
28						
29	UTAH					
30	08CFR00012-STR LGTS (CONV		54			
31	08CFR00051-MTH FAC SRVCHG		4,529			
32	08CFR00062-STREET LIGHTS		79			
33	08OALT007N-SECURITY AR LG	5	1,460	4	1,250	0.2920
34	08TOSS015F-TRAFFIC SIG NM	1,152	105,759	121	9,521	0.0918
35	08SLCO0011-STR LGT CO-OWN	14,920	4,556,874	759	19,657	0.3054
36	08TOSS0015-TRAF & OTHER S	2,957	350,400	1,530	1,933	0.1185
37	08MONL0015-MTR OUTDONIGHT	766	62,911	71	10,789	0.0821
38	08SLCU012P-STR LGT CUST-O	4,760	609,294	193	24,663	0.1280
39	08SLCU012F-STR LGT CUST-O	1,172	164,638	79	14,835	0.1405
40	08SLCU012E-DECOR CUST-OWN	50,473	3,283,937	696	72,519	0.0651
41	TOTAL Billed	54,671,093	4,872,459,725	1,812,975	30,155	0.0891
42	Total Unbilled Rev.(See Instr. 6)	-29,881	1,172,000	0	0	-0.0392
43	TOTAL	54,641,212	4,873,631,725	1,812,975	30,139	0.0892

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1	DSM REVENUE-PUB ST & HWY LT		331,057			
2	REVENUE_ACCT ADJ		-59,570			
3	SOLAR FEED-IN REVENUE		26,166			
4	UNBILLED REVENUE	-188	-25,000			0.1330
5						
6	WASHINGTON					
7	02CFR00012-STR LGTS (CONV		91			
8	02COSL0052-WA STR LGT SRV	189	34,477	14	13,500	0.1824
9	02CUSL053F-WA STR LGT SRV	3,445	248,880	111	31,036	0.0722
10	02CUSL053M-WA STR LGT SRV	1,137	81,291	105	10,829	0.0715
11	02SLCO0051-WA COMPANY	3,876	764,641	170	22,800	0.1973
12	02MVSL0057-WA MERC VAPSTR	1,729	219,241	40	43,225	0.1268
13	WASHINGTON - CHEHALIS DEF		-30,000			
14	DSM REVENUE-PUB ST & HWY LT		27,040			
15	REVENUE ADJ - DEF NPC		5,417			
16	REVENUE_ACCT ADJ		-26,390			
17	UNBILLED REVENUE	-236	-29,000			0.1229
18						
19	WYOMING					
20	05COSL0057-CO-OWND STR LG	268	54,487	17	15,765	0.2033
21	05CUSL058M-CUST OWND STR	78	4,958	11	7,091	0.0636
22	05CUSL0E58-CUST OWNED STR	1,069	67,575	30	35,633	0.0632
23	05CUSL0M58-CUST OWNED STR	43	3,280	3	14,333	0.0763
24	05HPSV0051-HI PRESSURE SO	5,313	1,088,249	179	29,682	0.2048
25	05MVS00053-MERCURY VAPOR	3,684	464,342	249	14,795	0.1260
26	05OALT015N-OUTD AR LGT SR	26	2,923	2	13,000	0.1124
27	DSM REVENUE-PUB ST & HWY LT		31,015			
28	REVENUE_ACCT ADJ		-53			
29	UNBILLED REVENUE	-51	-10,000			0.1961
30	09MONL0213-WY MTR OUTDOOR	26	2,708	1	26,000	0.1042
31	09SLCO0211-STR LGT CO-OWN	1,491	374,586	50	29,820	0.2512
32	09SLCUP212-CUST OWNED	34	5,534	5	6,800	0.1628
33	09TOSS0213-TRAFFIC & OTHER	41	2,282	14	2,929	0.0557
34	DSM REVENUE-PUB ST & HWY LT		883			
35	UNBILLED REVENUE	99	24,000			0.2424
36						
37	LESS MULTIPLE BILLINGS			-2,778		
38						
39	TOTAL PUBLIC STREET & HWY LT	140,686	19,942,747	3,496	40,242	0.1418
40						
41	TOTAL Billed	54,671,093	4,872,459,725	1,812,975	30,155	0.0891
42	Total Unbilled Rev.(See Instr. 6)	-29,881	1,172,000	0	0	-0.0392
43	TOTAL	54,641,212	4,873,631,725	1,812,975	30,139	0.0892

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1	OTHER SALES TO PUBLIC AUTH					
2	UTAH					
3	08GNSV009M-MANL HIGH VOLT	245,256	14,047,644	1	245,256,000	0.0573
4	08PRSV031M-BKUP MNT&SUPPL	25,658	2,334,254	2	12,829,000	0.0910
5	DSM REVENUE-OSPA		603,595			
6	REVENUE_ACCT ADJ		-96,304			
7	SOLAR FEED-IN REVENUE		37,872			
8	UNBILLED REVENUE	-449	-25,000			0.0557
9						
10	TOTAL OTHER SALES TO PUBLIC	270,465	16,902,061	3	90,155,000	0.0625
11						
12	FORFEITED DISCOUNTS					
13	CALIFORNIA					
14	06LPAY0300-RES-LATEFEE		178,725			
15	06LPAY0300-COM-LATEFEE		55,324			
16	06LPAY0300-IND-LATEFEE		48,570			
17	06LPAY0300-OTHER-LATEFEE		1,373			
18						
19	IDAHO					
20	07LPAY0300-RES-LATEFEE		199,427			
21	07LPAY0300-COM-LATEFEE		35,505			
22	07LPAY0300-IND-LATEFEE		172,301			
23	07LPAY0300-OTHER-LATEFEE		717			
24						
25	OREGON					
26	01LPAY0300-RES-LATEFEE		2,825,166			
27	01LPAY0300-COM-LATEFEE		599,977			
28	01LPAY0300-IND-LATEFEE		189,013			
29	01LPAY0300-OTHER-LATEFEE		33,225			
30						
31	UTAH					
32	08LPAY0300-RES-LATEFEE		2,449,738			
33	08LPAY0300-COM-LATEFEE		713,802			
34	08LPAY0300-IND-LATEFEE		251,999			
35	08LPAY0300-OTHER-LATEFEE		62,823			
36	OTHER		1,138			
37						
38	WASHINGTON					
39	02LPAY0300-RES-LATEFEE		470,625			
40	02LPAY0300-COM-LATEFEE		107,345			
41	TOTAL Billed	54,671,093	4,872,459,725	1,812,975	30,155	0.0891
42	Total Unbilled Rev.(See Instr. 6)	-29,881	1,172,000	0	0	-0.0392
43	TOTAL	54,641,212	4,873,631,725	1,812,975	30,139	0.0892

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1	02LPAY0300-IND-LATEFEE		28,345			
2	02LPAY0300-OTHER-LATEFEE		7,933			
3						
4	WYOMING					
5	05LPAY0300-RES-LATEFEE		394,935			
6	05LPAY0300-COM-LATEFEE		99,796			
7	05LPAY0300-IND-LATEFEE		145,406			
8	05LPAY0300-OTHER-LATEFEE		2,708			
9	05LPAY0300-RES-LATEFEE		46,777			
10	05LPAY0300-COM-LATEFEE		11,380			
11	05LPAY0300-IND-LATEFEE		6,814			
12	05LPAY0300-OTHER-LATEFEE		390			
13						
14	TOTAL FORFEITED DISCOUNTS		9,141,277			
15						
16	MISCELLANEOUS SERVICE REV					
17	CALIFORNIA					
18	06CFR00003-MTH MAINTENANC		1,454			
19	06CONN0300-CA RECONNECTIO		29,795			
20	06FCBUYOUT		47,114			
21	06RCHK0300-CA RET CHK CHR		10,320			
22	06TAMP0300-CA TAMP & UNAU		1,050			
23	06TEMP0300-CA TEMP SRVC C		3,205			
24	06XMTRTAMP-TMPRING - UNAU		226			
25	HOME COMFORT		126			
26	OTHER		-237			
27						
28	IDAHO					
29	07CFR00001-MTH FAC SRVCHG		1,682			
30	07CONN0300-ID RECONNECTIO		28,010			
31	07FCBUYOUT - FAC CHG BUYOUT		5,282			
32	07RCHK0300-ID RET CHK CHR		28,940			
33	07TEMP0014-TEMP SRVC CONN		24,625			
34	OTHER		8			
35						
36	OREGON					
37	01CFR00001-MTH FACILITY S		115,184			
38	01CFR00003-MTH MAINTENANC		25,942			
39	01CFR00004-MTH MAINTENANC		25,708			
40	01CFR00005-INTERMTNT SRVC		37,179			
41	TOTAL Billed	54,671,093	4,872,459,725	1,812,975	30,155	0.0891
42	Total Unbilled Rev.(See Instr. 6)	-29,881	1,172,000	0	0	-0.0392
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1	01CFR00013-MTH MISC CHRG		28,213			
2	01CFR00014-YR MISC CHRG		5			
3	01CONN0300-RECONNECTION C		354,235			
4	01CONTSERV-OR 3RD PARTY		8,412			
5	01ESSC0600 - ESS CHARGES		270			
6	01FCBUYOUT-FAC CHG BUYOUT		303,016			
7	01RCHK0300-RETURNED CHECK		265,820			
8	01TAMP0300-TAMP & UNAUTH		15,000			
9	01TEMP0300-TEMP SRVC CHRG		156,810			
10	01XMTRTAMP-TAMPRING - UNAU		3,531			
11	OTHER		-98,887			
12						
13	UTAH					
14	08CFR00013-MTH MISC CHRG		147,885			
15	08CFR00051-MTH FAC SRVCHG		87,386			
16	08CFR00052-ANN FAC SVCCHG		424			
17	08CFR00053-MTHLY MAINTFEE		11,646			
18	08CFR00054-NRES EMERGENCY		4,976			
19	08CFR00063-MTH MISC CHARG		2,373			
20	08CFR00064-ANN MISC CHARG		6,660			
21	08CONN0300-RECONN&DISCONN		344,590			
22	08CONTSERV-3RD PARTY O/S		84,711			
23	08FCBUYOUT-FAC CHG BUYOUT		142,513			
24	08INFO0300-CUST/3RD P REQ		354			
25	08METR0300-UT FEE MTR TES		60			
26	08NCON0300-UT FEE NRES RE		3,675			
27	08NSMTR300-NON STAN MTR		1,132			
28	08PRINT300-SCREEN PRINT FOR		254			
29	08RCHK0300-UT RET CHK CHR		441,321			
30	08RCON0001-CONNECT FEE		1,735,951			
31	08RESD0001-RES SRVC		3,166			
32	08TAMP0300-TAMPERING&UNAU		9,600			
33	08TEMP0014-TEMP SRVC CONN		556,031			
34	08XMTRTAMP-TMPRING - UNAU		1,013			
35	ENERGY FINANSWER NEW COM		4,095			
36	08VISIT300 - UT VISIT, SERVICE		49,165			
37	OTHER		-42,351			
38						
39	WASHINGTON					
40	02CFR00003-MTH MAINTENANC		1,320			
41	TOTAL Billed	54,671,093	4,872,459,725	1,812,975	30,155	0.0891
42	Total Unbilled Rev.(See Instr. 6)	-29,881	1,172,000	0	0	-0.0392
43	TOTAL	54,641,212	4,873,631,725	1,812,975	30,139	0.0892

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1	02CFR00004-EMRGNCY ST&BY		5,892			
2	02CFR00005-INTERMTNT SRVC		4,302			
3	02CONN0300-WA RECONNECTIO		104,870			
4	02FCBUYOUT - FAC CHG BUYOUT		13,717			
5	02RCHK0300-WA RET CHK CHR		54,260			
6	02TAMP0300-WA TAMP & UNAU		5,475			
7	02TEMP0300-WA TEMP SRVC C		22,220			
8	02XMTRTAMP-TMPRING - UNAU		1,409			
9	02XTHEFREV-THEFT OF		5,809			
10	HOME COMFORT		281			
11	OTHER		-33,684			
12						
13	WYOMING					
14	05CFR00003-MTH MAINTENANC		1,768			
15	05CFR00004-EMRGNCY ST&BY		18,424			
16	05CFR00005-INTERMTNT SRVC		10,132			
17	05CFR00013-MTH MISC CHRG		3,186			
18	05CONN0300-WY RECONNECTIO		76,041			
19	05FCBUYOUT - FAC CHG BUYOUT		48,185			
20	05NSMTR300-NON STANDARD		839			
21	05RCHK0300-WY RET CHK CHR		74,850			
22	05RESD0002-WY RES SRVC		66			
23	05SERV0300-WY SRVC CALLS		120			
24	05TAMP0300		450			
25	05TEMP0300-WY TEMP SRVC C		63,495			
26	05XMTRTAMP-TMPRING - UNAU		93			
27	09CFR00005-INTERMTNT SRVC		339			
28	OTHER		-267			
29	05CONN0300-WY RECONNECTIO		8,800			
30	05FCBUYOUT - FAC CHG BUYOUT		7,747			
31	05RCHK0300-WY RET CHK CHR		7,290			
32	09CFR00001-MTH FAC SRVCHG		5,103			
33	09CFR00014-YR MISC CHRG		3			
34	09TEMP0214-TEMP SRVC CONN		45			
35						
36	TOTAL MISC SERVICE REV		5,531,248			
37						
38	RENT FROM ELEC PROPERTIES					
39	CALIFORNIA					
40	06CFR00006-MTH RNTAL CHRG		1,710			
41	TOTAL Billed	54,671,093	4,872,459,725	1,812,975	30,155	0.0891
42	Total Unbilled Rev.(See Instr. 6)	-29,881	1,172,000	0	0	-0.0392
43	TOTAL	54,641,212	4,873,631,725	1,812,975	30,139	0.0892

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	RENT REVENUE-HYDRO		1,200			
2	RENT REVENUE-SUBLEASES		19,280			
3	JOINT USE		541,370			
4						
5	IDAHO					
6	07CFR00009-YR LSE CHRG-EQ		788			
7	07INVCHG00-INVEST MNT CHG		149			
8	07POLE0075-STEEL POLES US		276			
9	RENT REVENUE-HYDRO		91,832			
10	RENT REVENUE-TRANSMISSION		4,850			
11	RENT REVENUE-DISTRIBUTION		550			
12	RENT REVENUE-SUBLEASES		2,216			
13	JOINT USE		157,199			
14						
15	OREGON					
16	01CFR00006-MTH RNTAL CHRG		821,283			
17	RENTS - COMMON		732,419			
18	RENTS - NON COMMON		25			
19	MCI FOGWIRE REVENUE		3,345,901			
20	RENT REVENUE-SUBLEASES		36,707			
21	RENT REVENUE-HYDRO		24,726			
22	RENT REVENUE-TRANSMISSION		266,557			
23	RENT REVENUE-DISTRIBUTION		56,794			
24	RENT REVENUE-GENERAL		61,150			
25	JOINT USE		2,706,302			
26						
27	UTAH					
28	08CFR00056-MTH EQUIP RENT		33			
29	08CFR00058-MTH EQUIP LEAS		518,606			
30	08INVCHG0N-INVEST MNT CHG		4,407			
31	08INVCHG0R-INVEST MNT CHG		238			
32	08POLE0075-STEEL POLES US		54,601			
33	RENTS - NON COMMON		13,848			
34	RENT REVENUE-STEAM		103,995			
35	RENT REVENUE-HYDRO		101,524			
36	RENT REVENUE-TRANSMISSION		1,041,210			
37	RENT REVENUE-DISTRIBUTION		645,143			
38	RENT REVENUE-GENERAL		16,919			
39	RENT REVENUE-SUBLEASES		2,796,428			
40	INTERCOMPANY RENT REVENUE		28,822			
41	TOTAL Billed	54,671,093	4,872,459,725	1,812,975	30,155	0.0891
42	Total Unbilled Rev.(See Instr. 6)	-29,881	1,172,000	0	0	-0.0392
43	TOTAL	54,641,212	4,873,631,725	1,812,975	30,139	0.0892

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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	JOINT USE		2,984,423			
2						
3	WASHINGTON					
4	02CFR00001-MTH FACILITY S		2,123			
5	02CFR00006-MTH RNTAL CHRG		9,073			
6	RENT REVENUE-HYDRO		344,630			
7	RENT REVENUE-TRANSMISSION		18,649			
8	RENT REVENUE-DISTRIBUTION		20,744			
9	RENT REVENUE-GENERAL		41,174			
10	JOINT USE		843,243			
11						
12	WYOMING					
13	05CFR00001-MTH FACILITY S		11,524			
14	05CFR00006-MTH RNTAL CHRG		2,482			
15	RENT REVENUE-STEAM		23,436			
16	RENT REVENUE-HYDRO		18,284			
17	RENT REVENUE-TRANSMISSION		6,059			
18	RENT REVENUE-DISTRIBUTION		150			
19	RENT REVENUE-GENERAL		163,706			
20	RENT REVENUE-SUBLEASES		25,734			
21	JOINT USE		339,365			
22	09POLE0075-STEEL POLES US		18,313			
23	RENT REVENUE-STEAM		27,900			
24						
25	TOTAL RENT FROM ELEC PROP		19,100,070			
26						
27	OTHER ELECTRIC REVENUE					
28	WIND BASED ANCILLARY SVC		8,802,231			
29	FERC TRANSMISSION REFUND		-5,114,029			
30	OTH ELEC ESTIMATE		20,007			
31	RENEWABLE ENERGY CREDITS		-6,901,286			
32	CA GHG ALLOW REV AMORT		11,212,184			
33	NON-WHEELING SYSTEM		11,659,010			
34	OTHER ELEC (EXCLUDE WHEELIN		17,080			
35						
36	CALIFORNIA					
37	3RD PARTY TRANS O&M		53,869			
38	FISH, WILDLIFE, RECR		5,891			
39	OTHER ELEC (EXCLUDE WHEELIN		-61			
40						
41	TOTAL Billed	54,671,093	4,872,459,725	1,812,975	30,155	0.0891
42	Total Unbilled Rev.(See Instr. 6)	-29,881	1,172,000	0	0	-0.0392
43	TOTAL	54,641,212	4,873,631,725	1,812,975	30,139	0.0892

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	IDAHO					
2	3RD PARTY TRANS O&M		122,092			
3	OTHER ELEC (EXCLUDE WHEELIN		-1,917			
4						
5	OREGON					
6	EIM REVENUE - FORECASTING		38,400			
7	3RD PARTY TRANS O&M		1,872			
8	OTHER ELEC (EXCLUDE WHEELIN		2,260,928			
9						
10	UTAH					
11	ELEC INC-OTHR		62,627			
12	FLYASH SALES		2,379,327			
13	3RD PARTY TRANS O&M		128,481			
14	FISH, WILDLIFE, RECR		2,120			
15	I/C TRANS O&M REV - SIERRA		7,844			
16	OTHER ELEC (EXCLUDE WHEELIN		130			
17	M&S INVENTORY REVENUE		1,479,354			
18						
19	WASHINGTON					
20	TIMBER SALES - UTILITY PROP		6,222			
21	FISH, WILDLIFE, RECR		8,565			
22	OTHER ELEC (EXCLUDE WHEELIN		27			
23	WASH COLSTRIP 3		-52,188			
24						
25	WYOMING					
26	ELEC INC-OTHR		10			
27	FLYASH SALES		2,719,994			
28	WY REG RECOVERY FEE		317,733			
29	3RD PARTY TRANS O&M		21,980			
30	OTHER ELEC (EXCLUDE WHEELIN		3			
31						
32	TOTAL OTHER ELEC REV		29,258,500			
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	54,671,093	4,872,459,725	1,812,975	30,155	0.0891
42	Total Unbilled Rev.(See Instr. 6)	-29,881	1,172,000	0	0	-0.0392
43	TOTAL	54,641,212	4,873,631,725	1,812,975	30,139	0.0892

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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 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 Corporation	RQ	T-12	18.0	18.0	15
3	Helper City	RQ	T-6	1.0	1.0	0.9
4	Helper City Annex	RQ	T-6	0.7	0.6	0.6
5	Navajo Tribal Util. Auth. (Mexican Hat)	RQ	T-6	0.2	0.2	0.1
6	Navajo Tribal Util. Auth. (Red Mesa)	RQ	T-6	1.0	1.0	1.0
7	Portland General Electric Company	RQ	147	NA	NA	NA
8	Price City Corporation	RQ	T-12	11.0	11.0	10.0
9	Accrual	RQ	NA	NA	NA	NA
10						
11	Nonrequirement Sales:					
12	Arizona Electric Power Cooperative	SF	T-12	NA	NA	NA
13	Arizona Public Service Company	SF	T-12	NA	NA	NA
14	Avista Corporation	SF	T-12	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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
51,584	1,083,276	1,516,164		2,599,440	2
5,871	111,732	103,811		215,543	3
3,554	70,177	62,841		133,018	4
901	17,855	15,701		33,556	5
8,541	129,946	148,787		278,733	6
10,221		1,069,028		1,069,028	7
31,855	779,815	940,540	-80,927	1,639,428	8
16,030			782,687	782,687	9
					10
					11
125,780		2,688,603		2,688,603	12
55,938		1,610,143		1,610,143	13
46,813		969,924		969,924	14
128,557	2,192,801	3,856,872	701,760	6,751,433	
8,760,894	11,828,061	407,854,406	-156,600,278	263,082,189	
8,889,451	**14,020,862**	**411,711,278**	**-155,898,518**	**269,833,622**	

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	Avista Corporation	SF	T-13	NA	NA	NA
2	BP Energy Company	SF	T-12	NA	NA	NA
3	Barclays Bank PLC	SF	T-12	NA	NA	NA
4	Basin Electric Power Cooperative	AD	T-11	NA	NA	NA
5	Basin Electric Power Cooperative	LF	T-11	NA	NA	NA
6	Basin Electric Power Cooperative	SF	T-11	NA	NA	NA
7	Basin Electric Power Cooperative	SF	T-12	NA	NA	NA
8	Black Hills Power, Inc.	LF	441	50.0	50.0	49.0
9	Black Hills Power, Inc.	SF	T-12	NA	NA	NA
10	Black Hills Wyoming, Inc.	AD	T-11	NA	NA	NA
11	Black Hills Wyoming, Inc.	SF	T-11	NA	NA	NA
12	Bonneville Power Administration	AD	T-11	NA	NA	NA
13	Bonneville Power Administration	AD	T-12	NA	NA	NA
14	Bonneville Power Administration	LF	368	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.
52			1,422	1,422	1
470,488		13,330,158		13,330,158	2
23,575		893,493		893,493	3
-1			-8	-8	4
285			8,856	8,856	5
3,681			124,305	124,305	6
171,500		4,052,038		4,052,038	7
318,240	7,431,861	6,400,325		13,832,186	8
201,400		4,753,246		4,753,246	9
			-35	-35	10
26			903	903	11
396			11,882	11,882	12
			-123,645	-123,645	13
2,501			80,194	80,194	14
128,557	2,192,801	3,856,872	701,760	6,751,433	
8,760,894	11,828,061	407,854,406	-156,600,278	263,082,189	
8,889,451	**14,020,862**	**411,711,278**	**-155,898,518**	**269,833,622**	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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	Bonneville Power Administration	LF	T-11	NA	NA	NA
2	Bonneville Power Administration	LU	519	NA	NA	NA
3	Bonneville Power Administration	SF	T-11	NA	NA	NA
4	Bonneville Power Administration	SF	T-12	NA	NA	NA
5	Bonneville Power Administration	SF	T-13	NA	NA	NA
6	Bonneville Power Administration	SF	WSPP - Q	NA	NA	NA
7	British Columbia Hydro and Power	SF	T-13	NA	NA	NA
8	Brookfield Energy Marketing L.P.	SF	T-12	NA	NA	NA
9	California Independent System Operator	AD	T-12	NA	NA	NA
10	California Independent System Operator	SF	T-12	NA	NA	NA
11	Calpine Energy Services, L.P.	SF	T-12	NA	NA	NA
12	Cargill Power Markets, LLC	AD	T-11	NA	NA	NA
13	Cargill Power Markets, LLC	AD	T-12	NA	NA	NA
14	Cargill Power Markets, LLC	SF	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.
20,618			661,311	661,311	1
31,168		2,292,718		2,292,718	2
57			1,855	1,855	3
164,224		4,188,814		4,188,814	4
130			3,357	3,357	5
1,834		51,352		51,352	6
29			902	902	7
12,291		267,562		267,562	8
-4,244			-128,844	-128,844	9
65,730		2,186,648		2,186,648	10
39,413		812,320		812,320	11
			52	52	12
			600	600	13
1,248			44,647	44,647	14
128,557	2,192,801	3,856,872	701,760	6,751,433	
8,760,894	11,828,061	407,854,406	-156,600,278	263,082,189	
8,889,451	**14,020,862**	**411,711,278**	**-155,898,518**	**269,833,622**	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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 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	Cargill Power Markets, LLC	SF	T-12	NA	NA	NA
2	City of Anaheim	SF	T-11	NA	NA	NA
3	City of Burbank	SF	T-12	NA	NA	NA
4	City of Glendale	SF	T-12	NA	NA	NA
5	City of Hurricane	LF	T-12	NA	NA	NA
6	City of Redding	SF	T-12	NA	NA	NA
7	Clatskanie People's Utility District	SF	T-12	NA	NA	NA
8	ConocoPhillips Company	SF	T-12	NA	NA	NA
9	Constellation Energy Commodities Group	AD	T-12	NA	NA	NA
10	Deseret Generation & Transmission	SF	T-11	NA	NA	NA
11	EDF Trading North America, LLC	SF	T-12	NA	NA	NA
12	El Paso Electric Company	SF	T-12	NA	NA	NA
13	Eugene Water & Electric Board	SF	T-12	NA	NA	NA
14	Exelon Generation Company, LLC	LF	T-11	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 (2) [ ] A Resubmission	/ /	End of 2015/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.
1,152,111		32,730,604		32,730,604	1
594			19,828	19,828	2
59,279		1,338,677		1,338,677	3
5,378		123,541		123,541	4
236		15,340		15,340	5
67,400		1,560,009		1,560,009	6
1,987		42,725		42,725	7
400		16,100		16,100	8
			-119	-119	9
400			13,379	13,379	10
865,553		26,256,816		26,256,816	11
10,935		331,615		331,615	12
15,128		353,284		353,284	13
510			17,160	17,160	14
128,557	2,192,801	3,856,872	701,760	6,751,433	
8,760,894	11,828,061	407,854,406	-156,600,278	263,082,189	
8,889,451	**14,020,862**	**411,711,278**	**-155,898,518**	**269,833,622**	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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	Exelon Generation Company, LLC	SF	T-11	NA	NA	NA
2	Exelon Generation Company, LLC	SF	T-12	NA	NA	NA
3	Gridforce Energy Management, LLC	SF	T-13	NA	NA	NA
4	Iberdrola Renewables, LLC	AD	T-11	NA	NA	NA
5	Iberdrola Renewables, LLC	AD	T-12	NA	NA	NA
6	Iberdrola Renewables, LLC	LF	T-11	NA	NA	NA
7	Iberdrola Renewables, LLC	SF	T-11	NA	NA	NA
8	Iberdrola Renewables, LLC	SF	T-11	NA	NA	NA
9	Iberdrola Renewables, LLC	SF	T-12	NA	NA	NA
10	Idaho Power Company	LF	T-11	NA	NA	NA
11	Idaho Power Company	SF	T-11	NA	NA	NA
12	Idaho Power Company	SF	T-12	NA	NA	NA
13	Idaho Power Company	SF	T-13	NA	NA	NA
14	J. Aron & Company	AD	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 (2) [ ] A Resubmission	/ /	End of 2015/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.
9			206	206	1
2,459,161		71,816,667		71,816,667	2
85			1,763	1,763	3
532			14,171	14,171	4
			5	5	5
7,929			249,394	249,394	6
11,044			340,006	340,006	7
11			77	77	8
1,179,556		37,685,374		37,685,374	9
3,791			139,648	139,648	10
1,865			72,387	72,387	11
690		16,900		16,900	12
99			2,574	2,574	13
			-28	-28	14
128,557	2,192,801	3,856,872	701,760	6,751,433	
8,760,894	11,828,061	407,854,406	-156,600,278	263,082,189	
8,889,451	**14,020,862**	**411,711,278**	**-155,898,518**	**269,833,622**	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	J.P. Morgan Ventures Energy Corporation	SF	T-11	NA	NA	NA
2	Los Angeles Dept. of Water and Power	LU	301	NA	NA	NA
3	Los Angeles Dept. of Water and Power	SF	T-11	NA	NA	NA
4	Los Angeles Dept. of Water and Power	SF	T-12	NA	NA	NA
5	Macquarie Energy LLC	SF	T-11	NA	NA	NA
6	Macquarie Energy LLC	SF	T-12	NA	NA	NA
7	Modesto Irrigation District	SF	T-12	NA	NA	NA
8	Morgan Stanley Capital Group Inc.	AD	T-11	NA	NA	NA
9	Morgan Stanley Capital Group Inc.	SF	T-11	NA	NA	NA
10	Morgan Stanley Capital Group Inc.	SF	T-12	NA	NA	NA
11	Municipal Energy Agency of Nebraska	SF	T-11	NA	NA	NA
12	Municipal Energy Agency of Nebraska	SF	T-12	NA	NA	NA
13	NaturEner Power Watch, LLC	SF	T-13	NA	NA	NA
14	Nevada Power Company	SF	T-11	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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	1	1
569,850		26,570,488		26,570,488	2
126			3,677	3,677	3
17,591		406,409		406,409	4
2			32	32	5
167,903		4,421,836		4,421,836	6
47,630		1,215,879		1,215,879	7
			273	273	8
3,408			107,884	107,884	9
895,879		22,785,166		22,785,166	10
			1	1	11
73,454		1,626,735		1,626,735	12
57			1,186	1,186	13
185			8,228	8,228	14
128,557	2,192,801	3,856,872	701,760	6,751,433	
8,760,894	11,828,061	407,854,406	-156,600,278	263,082,189	
8,889,451	**14,020,862**	**411,711,278**	**-155,898,518**	**269,833,622**	

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	Nevada Power Company	SF	WSPP - Q	NA	NA	NA
2	NextEra Energy Power Marketing, LLC	LF	T-11	NA	NA	NA
3	NextEra Energy Power Marketing, LLC	SF	T-11	NA	NA	NA
4	NextEra Energy Power Marketing, LLC	SF	T-12	NA	NA	NA
5	Noble Americas Energy Solutions LLC	AD	T-11	NA	NA	NA
6	Noble Americas Energy Solutions LLC	LF	T-11	NA	NA	NA
7	NorthWestern Corporation	SF	T-12	NA	NA	NA
8	NorthWestern Corporation	SF	T-13	NA	NA	NA
9	Pacific Gas & Electric Company	SF	T-11	NA	NA	NA
10	Portland General Electric Company	SF	T-11	NA	NA	NA
11	Portland General Electric Company	SF	T-12	NA	NA	NA
12	Portland General Electric Company	SF	T-13	NA	NA	NA
13	Powerex Corporation	LF	T-11	NA	NA	NA
14	Powerex Corporation	SF	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.
80,001		1,764,831		1,764,831	1
6,510			195,098	195,098	2
430			14,531	14,531	3
800		24,400		24,400	4
894			19,527	19,527	5
10,574			343,584	343,584	6
18,354		430,276		430,276	7
175			3,902	3,902	8
70			1,912	1,912	9
373			15,763	15,763	10
112,719		2,458,392		2,458,392	11
3			92	92	12
30,745			1,035,406	1,035,406	13
16,410			536,645	536,645	14
128,557	2,192,801	3,856,872	701,760	6,751,433	
8,760,894	11,828,061	407,854,406	-156,600,278	263,082,189	
8,889,451	**14,020,862**	**411,711,278**	**-155,898,518**	**269,833,622**	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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	Powerex Corporation	SF	T-12	NA	NA	NA
2	Public Service Company of Colorado	SF	T-12	NA	NA	NA
3	Public Service Company of New Mexico	SF	T-12	NA	NA	NA
4	PUD No. 1 of Chelan County	SF	T-13	NA	NA	NA
5	PUD No. 1 of Clark County	SF	T-12	NA	NA	NA
6	PUD No. 1 of Douglas County	SF	T-12	NA	NA	NA
7	PUD No. 1 of Snohomish County	SF	T-12	NA	NA	NA
8	PUD No. 2 of Grant County	SF	T-12	NA	NA	NA
9	PUD No. 2 of Grant County	SF	T-13	NA	NA	NA
10	Puget Sound Energy, Inc.	SF	T-11	NA	NA	NA
11	Puget Sound Energy, Inc.	SF	T-12	NA	NA	NA
12	Puget Sound Energy, Inc.	SF	T-13	NA	NA	NA
13	Rainbow Energy Marketing Corporation	SF	T-11	NA	NA	NA
14	Rainbow Energy Marketing Corporation	SF	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.
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.
126,566		2,624,092	72,820	2,696,912	1
144,978		3,417,997		3,417,997	2
150,400		4,032,526		4,032,526	3
7			218	218	4
12,902		377,042		377,042	5
615		16,065		16,065	6
7,135		206,750		206,750	7
15,235		366,606		366,606	8
7			130	130	9
			2	2	10
26,550		587,470		587,470	11
40			1,143	1,143	12
23			780	780	13
191,954		4,440,746		4,440,746	14
128,557	2,192,801	3,856,872	701,760	6,751,433	
8,760,894	11,828,061	407,854,406	-156,600,278	263,082,189	
8,889,451	**14,020,862**	**411,711,278**	**-155,898,518**	**269,833,622**	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Sacramento Municipal Utility District	AD	250	NA	NA	NA
2	Sacramento Municipal Utility District	AD	T-11	NA	NA	NA
3	Sacramento Municipal Utility District	LF	T-11	NA	NA	NA
4	Sacramento Municipal Utility District	SF	T-12	NA	NA	NA
5	Sacramento Municipal Utility District	SF	T-13	NA	NA	NA
6	Salt River Project	LF	T-11	NA	NA	NA
7	Salt River Project	SF	T-11	NA	NA	NA
8	Salt River Project	SF	T-12	NA	NA	NA
9	Seattle City Light	SF	T-12	NA	NA	NA
10	Seattle City Light	SF	T-13	NA	NA	NA
11	Sempra Generation, LLC	SF	T-12	NA	NA	NA
12	Shell Energy North America (US), L.P.	AD	T-11	NA	NA	NA
13	Shell Energy North America (US), L.P.	LF	T-11	NA	NA	NA
14	Shell Energy North America (US), L.P.	SF	T-11	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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.
			261,923	261,923	1
			18	18	2
5,650			174,302	174,302	3
181,647		4,141,800		4,141,800	4
33			636	636	5
5,860			182,062	182,062	6
1,058			36,168	36,168	7
208,890		5,030,598		5,030,598	8
25,791		585,272		585,272	9
12			419	419	10
998,850		33,243,075		33,243,075	11
			-21	-21	12
3,128			101,220	101,220	13
1,250			38,067	38,067	14
128,557	2,192,801	3,856,872	701,760	6,751,433	
8,760,894	11,828,061	407,854,406	-156,600,278	263,082,189	
8,889,451	**14,020,862**	**411,711,278**	**-155,898,518**	**269,833,622**	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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 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	Shell Energy North America (US), L.P.	SF	T-12	NA	NA	NA
2	Sierra Pacific Power Company	SF	T-13	NA	NA	NA
3	Southern California Edison Company	SF	T-11	NA	NA	NA
4	Southern California Edison Company	SF	T-11	NA	NA	NA
5	Southern California Edison Company	SF	T-12	NA	NA	NA
6	Southern California Public Power Auth.	SF	T-11	NA	NA	NA
7	Tacoma Power	SF	T-12	NA	NA	NA
8	Tacoma Power	SF	T-13	NA	NA	NA
9	Talen Energy Marketing, LLC	SF	T-11	NA	NA	NA
10	Talen Energy Marketing, LLC	SF	T-12	NA	NA	NA
11	Tenaska Power Services Co.	AD	T-11	NA	NA	NA
12	Tenaska Power Services Co.	SF	T-11	NA	NA	NA
13	Tenaska Power Services Co.	SF	T-12	NA	NA	NA
14	The Energy Authority, Inc.	AD	T-11	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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.
503,934		13,508,250		13,508,250	1
239			4,644	4,644	2
3,211			102,435	102,435	3
17			491	491	4
64,609		1,489,340		1,489,340	5
3			104	104	6
19,605		442,420		442,420	7
50			833	833	8
564			22,585	22,585	9
14,074		293,473		293,473	10
			15	15	11
319			14,240	14,240	12
416,667		10,170,295		10,170,295	13
			-22	-22	14
128,557	2,192,801	3,856,872	701,760	6,751,433	
8,760,894	11,828,061	407,854,406	-156,600,278	263,082,189	
8,889,451	**14,020,862**	**411,711,278**	**-155,898,518**	**269,833,622**	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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 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	The Energy Authority, Inc.	SF	T-11	NA	NA	NA
2	The Energy Authority, Inc.	SF	T-12	NA	NA	NA
3	Thermo No. 1 BE-01, LLC	AD	T-11	NA	NA	NA
4	Thermo No. 1 BE-01, LLC	LF	T-11	NA	NA	NA
5	TransAlta Energy Marketing (U.S.) Inc.	AD	T-11	NA	NA	NA
6	TransAlta Energy Marketing (U.S.) Inc.	SF	T-11	NA	NA	NA
7	TransAlta Energy Marketing (U.S.) Inc.	SF	T-12	NA	NA	NA
8	TransCanada Energy Sales Ltd.	SF	T-12	NA	NA	NA
9	Tri-State Gen. and Trans.	AD	T-11	NA	NA	NA
10	Tri-State Gen. and Trans.	LF	T-11	NA	NA	NA
11	Tri-State Gen. and Trans.	SF	T-11	NA	NA	NA
12	Tri-State Gen. and Trans.	SF	T-12	NA	NA	NA
13	Tucson Electric Power Company	SF	T-11	NA	NA	NA
14	Tucson Electric Power Company	SF	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.
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.
543			36,343	36,343	1
64,599		1,606,488		1,606,488	2
			5	5	3
2,734			86,555	86,555	4
			-610	-610	5
1,906			64,011	64,011	6
262,300		6,426,770		6,426,770	7
6,000		157,200		157,200	8
			383	383	9
5,510			179,477	179,477	10
30			806	806	11
218,277		4,997,034		4,997,034	12
34			1,532	1,532	13
570,685		14,283,371		14,283,371	14
128,557	2,192,801	3,856,872	701,760	6,751,433	
8,760,894	11,828,061	407,854,406	-156,600,278	263,082,189	
8,889,451	**14,020,862**	**411,711,278**	**-155,898,518**	**269,833,622**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Turlock Irrigation District	SF	T-12	NA	NA	NA
2	UNS Electric, Inc.	SF	T-12	NA	NA	NA
3	Utah Associated Municipal Power Systems	SF	T-11	NA	NA	NA
4	Utah Associated Municipal Power Systems	SF	T-12	NA	NA	NA
5	Utah Municipal Power Agency	AD	637	NA	NA	NA
6	Utah Municipal Power Agency	LF	433	34	35	31
7	Utah Municipal Power Agency	LF	637	NA	NA	NA
8	Utah Municipal Power Agency	SF	T-12	NA	NA	NA
9	Vitol Inc.	SF	T-12	NA	NA	NA
10	Western Area Power Administration	AD	T-11	NA	NA	NA
11	Western Area Power Administration	SF	T-11	NA	NA	NA
12	Western Area Power Administration	SF	T-12	NA	NA	NA
13	Western Area Power Administration	SF	T-13	NA	NA	NA
14	Netting - Bookouts		NA	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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.
3,265		75,835		75,835	1
160,304		4,057,436		4,057,436	2
1,523			50,506	50,506	3
275		8,700		8,700	4
			-774	-774	5
219,570	4,396,200	5,095,790		9,491,990	6
22,803			827,633	827,633	7
2,393		54,136		54,136	8
89,378		2,560,096		2,560,096	9
			19	19	10
91			2,712	2,712	11
201,568		5,068,325		5,068,325	12
2			43	43	13
-5,859,056			-161,672,255	-161,672,255	14
128,557	2,192,801	3,856,872	701,760	6,751,433	
8,760,894	11,828,061	407,854,406	-156,600,278	263,082,189	
8,889,451	**14,020,862**	**411,711,278**	**-155,898,518**	**269,833,622**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	Netting - Trading		NA	NA	NA	NA
2	Accrual		NA	NA	NA	NA
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,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.
			-496,450	-496,450	1
2,289			-541,373	-541,373	2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
128,557	2,192,801	3,856,872	701,760	6,751,433	
8,760,894	11,828,061	407,854,406	-156,600,278	263,082,189	
8,889,451	**14,020,862**	**411,711,278**	**-155,898,518**	**269,833,622**	

Schedule Page: 310 Line No.: 5 Column: a

This footnote applies to all occurrences of "Navajo Tribal Util. Auth. (Mexican Hat)" on pages 310-311. Complete name is Navajo Tribal Utility Authority (Mexican Hat).

Schedule Page: 310 Line No.: 6 Column: a

This footnote applies to all occurrences of "Navajo Tribal Util. Auth. (Red Mesa)" on pages 310-311. Complete name is Navajo Tribal Utility Authority (Red Mesa).

Schedule Page: 310 Line No.: 8 Column: j

Settlement adjustment.

Schedule Page: 310 Line No.: 9 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, Sales for resale, during the period.

Schedule Page: 310.1 Line No.: 1 Column: j

Reserve share.

Schedule Page: 310.1 Line No.: 4 Column: b

Settlement adjustment.

Schedule Page: 310.1 Line No.: 4 Column: j

Settlement adjustment.

Schedule Page: 310.1 Line No.: 5 Column: b

Basin Electric Power Cooperative - FERC T-11 [Network Transmission Service under the Open Access Transmission Tariff (2nd Revised Service Agreement 505)] - Contract termination no earlier than 12 months from notice.

Schedule Page: 310.1 Line No.: 5 Column: j

Transmission losses.

Schedule Page: 310.1 Line No.: 6 Column: j

Transmission losses.

Schedule Page: 310.1 Line No.: 8 Column: b

Black Hills Power, Inc. - FERC 441 - Contract termination date: December 31, 2023.

Schedule Page: 310.1 Line No.: 10 Column: b

Settlement adjustment.

Schedule Page: 310.1 Line No.: 10 Column: j

Settlement adjustment.

Schedule Page: 310.1 Line No.: 11 Column: j

Transmission losses.

Schedule Page: 310.1 Line No.: 12 Column: b

Settlement adjustment.

Schedule Page: 310.1 Line No.: 12 Column: j

Settlement adjustment.

Schedule Page: 310.1 Line No.: 13 Column: b

Settlement adjustment.

Schedule Page: 310.1 Line No.: 13 Column: j

Settlement adjustment.

Schedule Page: 310.1 Line No.: 14 Column: b

Bonneville Power Administration ("BPA") - FERC, 13th revised R.S. 368 [Use of Facilities Agreement for the Malin Transformer under the AC Intertie Agreement with BPA] - Contract termination date: Upon mutual agreement.

Schedule Page: 310.1 Line No.: 14 Column: j

Transmission losses.

Schedule Page: 310.2 Line No.: 1 Column: b

Bonneville Power Administration - FERC T-11 [Network and Point-to-Point Services under the Open Access Transmission Tariff] - Contracts terminate September 30, 2025 through August 31, 2030.

Schedule Page: 310.2 Line No.: 1 Column: j

Transmission losses.

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

Schedule Page: 310.2 Line No.: 5 Column: j
Reserve share.

Schedule Page: 310.2 Line No.: 7 Column: a
This footnote applies to all occurrences of "British Columbia Hydro and Power" on pages 310-311. Complete name is British Columbia Hydro and Power Authority.

Schedule Page: 310.2 Line No.: 7 Column: j
Reserve share.

Schedule Page: 310.2 Line No.: 9 Column: a
This footnote applies to all occurrences of "California Independent System Operator" on pages 310-311. Complete name is California Independent System Operator Corporation.

Schedule Page: 310.2 Line No.: 9 Column: b
Settlement adjustment.

Schedule Page: 310.2 Line No.: 9 Column: j
Settlement adjustment.

Schedule Page: 310.2 Line No.: 12 Column: b
Settlement adjustment.

Schedule Page: 310.2 Line No.: 12 Column: j
Settlement adjustment.

Schedule Page: 310.2 Line No.: 13 Column: b
Settlement adjustment.

Schedule Page: 310.2 Line No.: 13 Column: j
Settlement adjustment.

Schedule Page: 310.2 Line No.: 14 Column: j
Transmission losses.

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

Schedule Page: 310.3 Line No.: 5 Column: b
City of Hurricane - FERC T-12 - Contract termination date: August 31, 2017.

Schedule Page: 310.3 Line No.: 9 Column: a
This footnote applies to all occurrences of "Constellation Energy Commodities Group" on pages 310-311. Complete name is Constellation Energy Commodities Group, Inc.

Schedule Page: 310.3 Line No.: 9 Column: b
Settlement adjustment.

Schedule Page: 310.3 Line No.: 9 Column: j
Settlement adjustment.

Schedule Page: 310.3 Line No.: 10 Column: a
This footnote applies to all occurrences of "Deseret Generation & Transmission" on pages 310-311. Complete name is Deseret Generation & Transmission Co-operative.

Schedule Page: 310.3 Line No.: 10 Column: j
Transmission losses.

Schedule Page: 310.3 Line No.: 14 Column: b
Exelon Generation Company, LLC - FERC T-11 [Network Transmission Service under the Open Access Transmission Tariff (Service Agreement 789)] - Contract termination upon notification pursuant to Oregon Direct Access and Open Access Transmission Tariff.

Schedule Page: 310.3 Line No.: 14 Column: j
Transmission losses.

Schedule Page: 310.4 Line No.: 1 Column: j
Unauthorized use charges.

Schedule Page: 310.4 Line No.: 3 Column: j
Reserve share.

Schedule Page: 310.4 Line No.: 4 Column: b
Settlement adjustment.

Schedule Page: 310.4 Line No.: 4 Column: j
Settlement adjustment.

Schedule Page: 310.4 Line No.: 5 Column: b
Settlement adjustment.

Schedule Page: 310.4 Line No.: 5 Column: j
Settlement adjustment.

Schedule Page: 310.4 Line No.: 6 Column: b
Iberdrola Renewables, LLC - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (8th Revised S.A. 279)] - Contract termination date: April 30, 2019.

Schedule Page: 310.4 Line No.: 6 Column: j
Transmission losses.

Schedule Page: 310.4 Line No.: 7 Column: j
Transmission losses.

Schedule Page: 310.4 Line No.: 8 Column: j
Unauthorized use charges.

Schedule Page: 310.4 Line No.: 10 Column: b
Idaho Power Company - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (8th Revised S.A. 212)] - Contract termination date: May 31, 2019.

Schedule Page: 310.4 Line No.: 10 Column: j
Transmission losses.

Schedule Page: 310.4 Line No.: 11 Column: j
Transmission losses.

Schedule Page: 310.4 Line No.: 13 Column: j
Reserve share.

Schedule Page: 310.4 Line No.: 14 Column: b
Settlement adjustment.

Schedule Page: 310.4 Line No.: 14 Column: j
Settlement adjustment.

Schedule Page: 310.5 Line No.: 1 Column: j
Unauthorized use charges.

Schedule Page: 310.5 Line No.: 2 Column: a
This footnote applies to all occurrences of "Los Angeles Dept. of Water and Power" on pages 310-311. Complete name is Los Angeles Department of Water and Power.

Schedule Page: 310.5 Line No.: 3 Column: j
Transmission losses.

Schedule Page: 310.5 Line No.: 5 Column: j
Transmission losses.

Schedule Page: 310.5 Line No.: 8 Column: b
Settlement adjustment.

Schedule Page: 310.5 Line No.: 8 Column: j
Settlement adjustment.

Schedule Page: 310.5 Line No.: 9 Column: j
Transmission losses.

Schedule Page: 310.5 Line No.: 11 Column: j
Transmission losses.

Schedule Page: 310.5 Line No.: 13 Column: j
Reserve share.

Schedule Page: 310.5 Line No.: 14 Column: a
This footnote applies to all occurrences of "Nevada Power Company" on pages 310-311. Nevada Power Company is a principal subsidiary of NV Energy, Inc., which is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company, PacifiCorp's indirect parent company.

Schedule Page: 310.5 Line No.: 14 Column: j

Transmission losses.

Schedule Page: 310.6 Line No.: 2 Column: b

NextEra Energy Power Marketing, LLC - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (2nd Revised S.A. 733)] - Contract termination date: November 17, 2017.

Schedule Page: 310.6 Line No.: 2 Column: j

Transmission losses.

Schedule Page: 310.6 Line No.: 3 Column: j

Transmission losses.

Schedule Page: 310.6 Line No.: 5 Column: b

Settlement adjustment.

Schedule Page: 310.6 Line No.: 5 Column: j

Settlement adjustment.

Schedule Page: 310.6 Line No.: 6 Column: b

Noble Americas Energy Solutions LLC - FERC T-11 [Network Transmission Service under the Open Access Transmission Tariff (6th Revised Service Agreement 299)] - Contract termination upon notification pursuant to Oregon Direct Access and Open Access Transmission Tariff.

Schedule Page: 310.6 Line No.: 6 Column: j

Transmission losses.

Schedule Page: 310.6 Line No.: 8 Column: j

Reserve share.

Schedule Page: 310.6 Line No.: 9 Column: j

Transmission losses.

Schedule Page: 310.6 Line No.: 10 Column: j

Transmission losses.

Schedule Page: 310.6 Line No.: 12 Column: j

Reserve share.

Schedule Page: 310.6 Line No.: 13 Column: b

Powerex Corporation - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (8th Revised S.A. 169)] - Contract termination date: October 31, 2020.

Schedule Page: 310.6 Line No.: 13 Column: j

Transmission losses.

Schedule Page: 310.6 Line No.: 14 Column: j

Transmission losses.

Schedule Page: 310.7 Line No.: 1 Column: j

Pond sales.

Schedule Page: 310.7 Line No.: 4 Column: a

This footnote applies to all occurrences of "PUD No. 1 of Chelan County" on pages 310-311. Complete name is Public Utility District No. 1 of Chelan County.

Schedule Page: 310.7 Line No.: 4 Column: j

Reserve share.

Schedule Page: 310.7 Line No.: 5 Column: a

This footnote applies to all occurrences of "PUD No. 1 of Clark County" on pages 310-311. Complete name is Public Utility District No. 1 of Clark County.

Schedule Page: 310.7 Line No.: 6 Column: a

This footnote applies to all occurrences of "PUD No. 1 of Douglas County" on pages 310-311. Complete name is Public Utility District No. 1 of Douglas County.

Schedule Page: 310.7 Line No.: 7 Column: a

This footnote applies to all occurrences of "PUD No. 1 of Snohomish County" on pages 310-311. Complete name is Public Utility District No. 1 of Snohomish County.

Schedule Page: 310.7 Line No.: 8 Column: a

This footnote applies to all occurrences of "PUD No. 2 of Grant County" on pages 310-311. Complete name is Public Utility District No. 2 of Grant County.

Schedule Page: 310.7 Line No.: 9 Column: j
Reserve share.
Schedule Page: 310.7 Line No.: 10 Column: j
Transmission losses.
Schedule Page: 310.7 Line No.: 12 Column: j
Reserve share.
Schedule Page: 310.7 Line No.: 13 Column: j
Transmission losses.
Schedule Page: 310.8 Line No.: 1 Column: b
Settlement adjustment.
Schedule Page: 310.8 Line No.: 1 Column: j
Settlement adjustment.
Schedule Page: 310.8 Line No.: 2 Column: b
Settlement adjustment.
Schedule Page: 310.8 Line No.: 2 Column: j
Settlement adjustment.
Schedule Page: 310.8 Line No.: 3 Column: b
Sacramento Municipal Utility District - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (Service Agreement 795)] - Contract termination date: December 31, 2020.
Schedule Page: 310.8 Line No.: 3 Column: j
Transmission losses.
Schedule Page: 310.8 Line No.: 5 Column: j
Reserve share.
Schedule Page: 310.8 Line No.: 6 Column: b
Salt River Project - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (Service Agreement 809)] - Contract termination date: October 31, 2020.
Schedule Page: 310.8 Line No.: 6 Column: j
Transmission losses.
Schedule Page: 310.8 Line No.: 7 Column: j
Transmission losses.
Schedule Page: 310.8 Line No.: 10 Column: j
Reserve share.
Schedule Page: 310.8 Line No.: 12 Column: b
Settlement adjustment.
Schedule Page: 310.8 Line No.: 12 Column: j
Settlement adjustment.
Schedule Page: 310.8 Line No.: 13 Column: b
Shell Energy North America (US), L.P. - FERC T-11 [Re-Sale Transmission Service under the Open Access Transmission Tariff (Service Agreement 791)] - Resale termination upon agreement between resale parties.
Schedule Page: 310.8 Line No.: 13 Column: j
Transmission losses.
Schedule Page: 310.8 Line No.: 14 Column: j
Transmission losses.
Schedule Page: 310.9 Line No.: 2 Column: a
This footnote applies to all occurrences of "Sierra Pacific Power Company" on pages 310-311. Sierra Pacific Power Company is a principal subsidiary of NV Energy, Inc., which is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company, PacifiCorp's indirect parent company.
Schedule Page: 310.9 Line No.: 2 Column: j
Reserve share.
Schedule Page: 310.9 Line No.: 3 Column: j

Transmission losses.

Schedule Page: 310.9 Line No.: 4 Column: j

Unauthorized use charges.

Schedule Page: 310.9 Line No.: 6 Column: a

This footnote applies to all occurrences of "Southern California Public Power Auth." on pages 310-311. Complete name is Southern California Public Power Authority.

Schedule Page: 310.9 Line No.: 6 Column: j

Unauthorized use charges.

Schedule Page: 310.9 Line No.: 8 Column: j

Reserve share.

Schedule Page: 310.9 Line No.: 9 Column: j

Transmission losses.

Schedule Page: 310.9 Line No.: 11 Column: b

Settlement adjustment.

Schedule Page: 310.9 Line No.: 11 Column: j

Settlement adjustment.

Schedule Page: 310.9 Line No.: 12 Column: j

Transmission losses.

Schedule Page: 310.9 Line No.: 14 Column: b

Settlement adjustment.

Schedule Page: 310.9 Line No.: 14 Column: j

Settlement adjustment.

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

Thermo No. 1 BE-01, LLC - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (3rd Revised Service Agreement 568)] - Contract termination date: April 30, 2029.

Schedule Page: 310.10 Line No.: 4 Column: j

Transmission losses.

Schedule Page: 310.10 Line No.: 5 Column: b

Settlement adjustment.

Schedule Page: 310.10 Line No.: 5 Column: j

Settlement adjustment.

Schedule Page: 310.10 Line No.: 6 Column: j

Transmission losses.

Schedule Page: 310.10 Line No.: 9 Column: a

This footnote applies to all occurrences of "Tri-State Gen. and Trans." on pages 310-311. Complete name is Tri-State Generation and Transmission Association, Inc.

Schedule Page: 310.10 Line No.: 9 Column: b

Settlement adjustment.

Schedule Page: 310.10 Line No.: 9 Column: j

Settlement adjustment.

Schedule Page: 310.10 Line No.: 10 Column: b

Tri-State Generation and Transmission Association, Inc. - FERC T-11 [Network Transmission Service under the Open Access Transmission Tariff (6th Revised Service Agreement 628)] - Contract termination date: June 30, 2021.

Schedule Page: 310.10 Line No.: 10 Column: j

Transmission losses.

Schedule Page: 310.10 Line No.: 11 Column: j

Transmission losses.

Schedule Page: 310.10 Line No.: 13 Column: j

Transmission losses.

Schedule Page: 310.11 Line No.: 3 Column: j

Transmission losses.

Schedule Page: 310.11 Line No.: 5 Column: b

Settlement adjustment.

Schedule Page: 310.11 Line No.: 5 Column: j

Settlement adjustment.

Schedule Page: 310.11 Line No.: 6 Column: b

Utah Municipal Power Agency - Legacy Contract [Transmission Service over agreed upon facilities (5th Revised Rate Schedule 637)] - Subject to termination upon mutual agreement and replacement agreements are in effect.

Schedule Page: 310.11 Line No.: 7 Column: b

Utah Municipal Power Agency - FERC 433 - Contract termination date: June 30, 2017.

Schedule Page: 310.11 Line No.: 7 Column: j

Transmission losses.

Schedule Page: 310.11 Line No.: 10 Column: b

Settlement adjustment.

Schedule Page: 310.11 Line No.: 10 Column: j

Settlement adjustment.

Schedule Page: 310.11 Line No.: 11 Column: j

Transmission losses.

Schedule Page: 310.11 Line No.: 13 Column: j

Reserve share.

Schedule Page: 310.11 Line No.: 14 Column: j

Reflects transactions that did not physically settle.

Schedule Page: 310.12 Line No.: 1 Column: j

Reflects transactions that did not physically settle.

Schedule Page: 310.12 Line No.: 2 Column: j

Represents the difference between actual non-requirement sales revenues for the period as reflected on the individual line items within this schedule, and the accruals charged to Account 447, Sales for resale, during the period.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	15,517,011	18,509,642
5	(501) Fuel	893,792,204	860,709,193
6	(502) Steam Expenses	84,614,045	43,153,691
7	(503) Steam from Other Sources	3,980,975	4,303,809
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,351,648	3,921,304
10	(506) Miscellaneous Steam Power Expenses	-15,574,943	41,560,988
11	(507) Rents	394,702	379,252
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	985,075,642	972,537,879
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	8,514,939	6,742,774
16	(511) Maintenance of Structures	30,664,954	28,711,998
17	(512) Maintenance of Boiler Plant	95,031,926	114,942,694
18	(513) Maintenance of Electric Plant	34,835,090	44,711,216
19	(514) Maintenance of Miscellaneous Steam Plant	11,894,236	11,939,661
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	180,941,145	207,048,343
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	1,166,016,787	1,179,586,222
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	8,836,151	7,346,206
45	(536) Water for Power	121,947	200,374
46	(537) Hydraulic Expenses	4,327,999	4,387,105
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses	17,875,790	16,721,432
49	(540) Rents	1,573,497	921,405
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	32,735,384	29,576,522
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	388	388
54	(542) Maintenance of Structures	907,301	797,907
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,413,192	1,890,427
56	(544) Maintenance of Electric Plant	1,749,826	1,991,634
57	(545) Maintenance of Miscellaneous Hydraulic Plant	3,016,038	3,739,521
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	7,086,745	8,419,877
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	39,822,129	37,996,399

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	418,092	353,767
63	(547) Fuel	272,426,195	396,700,941
64	(548) Generation Expenses	18,238,116	17,772,523
65	(549) Miscellaneous Other Power Generation Expenses	7,745,388	9,084,850
66	(550) Rents	3,491,472	4,187,040
67	TOTAL Operation (Enter Total of lines 62 thru 66)	302,319,263	428,099,121
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	4,228,009	2,279,301
71	(553) Maintenance of Generating and Electric Plant	26,813,693	17,425,171
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,481,768	2,986,641
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	32,523,470	22,691,113
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	334,842,733	450,790,234
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	623,108,136	603,201,899
77	(556) System Control and Load Dispatching	1,426,643	1,262,603
78	(557) Other Expenses	48,032,087	53,534,340
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	672,566,866	657,998,842
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	2,213,248,515	2,326,371,697
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	9,280,674	5,651,643
84			
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	6,818,716	7,564,076
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	2,106,756	824,276
89	(561.5) Reliability, Planning and Standards Development	1,326,587	1,111,085
90	(561.6) Transmission Service Studies	106,311	76,025
91	(561.7) Generation Interconnection Studies	998,299	1,139,487
92	(561.8) Reliability, Planning and Standards Development Services	7,402,436	5,545,389
93	(562) Station Expenses	3,072,973	3,333,301
94	(563) Overhead Lines Expenses	409,509	488,475
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	148,425,345	151,335,724
97	(566) Miscellaneous Transmission Expenses	2,400,520	4,350,698
98	(567) Rents	2,248,767	1,917,195
99	TOTAL Operation (Enter Total of lines 83 thru 98)	184,596,893	183,337,374
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	1,186,503	1,369,666
102	(569) Maintenance of Structures	19,905	-46,352
103	(569.1) Maintenance of Computer Hardware	105,911	111,446
104	(569.2) Maintenance of Computer Software	406,743	448,520
105	(569.3) Maintenance of Communication Equipment	3,624,514	3,573,267
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	8,037,307	7,895,835
108	(571) Maintenance of Overhead Lines	17,091,353	15,744,941
109	(572) Maintenance of Underground Lines	51,642	100,695
110	(573) Maintenance of Miscellaneous Transmission Plant	543,682	-1,477,863
111	TOTAL Maintenance (Total of lines 101 thru 110)	31,067,560	27,720,155
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	215,664,453	211,057,529

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	11,287,882	9,856,256
135	(581) Load Dispatching	11,746,191	12,031,560
136	(582) Station Expenses	4,235,949	4,646,431
137	(583) Overhead Line Expenses	6,808,598	5,735,189
138	(584) Underground Line Expenses	6,628	128
139	(585) Street Lighting and Signal System Expenses	223,951	231,729
140	(586) Meter Expenses	6,584,411	7,226,408
141	(587) Customer Installations Expenses	10,551,937	10,081,874
142	(588) Miscellaneous Expenses	4,670,374	5,691,371
143	(589) Rents	3,315,582	2,539,539
144	TOTAL Operation (Enter Total of lines 134 thru 143)	59,431,503	58,040,485
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	5,710,663	5,882,500
147	(591) Maintenance of Structures	2,230,204	2,239,835
148	(592) Maintenance of Station Equipment	11,414,124	12,488,442
149	(593) Maintenance of Overhead Lines	91,628,672	95,268,142
150	(594) Maintenance of Underground Lines	22,910,745	21,417,732
151	(595) Maintenance of Line Transformers	922,335	872,964
152	(596) Maintenance of Street Lighting and Signal Systems	3,252,544	3,389,842
153	(597) Maintenance of Meters	4,294,012	5,985,723
154	(598) Maintenance of Miscellaneous Distribution Plant	5,240,622	1,977,891
155	TOTAL Maintenance (Total of lines 146 thru 154)	147,603,921	149,523,071
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	207,035,424	207,563,556
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	1,739,975	2,621,299
160	(902) Meter Reading Expenses	17,341,069	17,785,403
161	(903) Customer Records and Collection Expenses	52,023,964	53,283,660
162	(904) Uncollectible Accounts	10,227,550	11,444,958
163	(905) Miscellaneous Customer Accounts Expenses	33,442	156,938
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	81,366,000	85,292,258

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	271,770	150,177
168	(908) Customer Assistance Expenses	132,301,137	132,017,498
169	(909) Informational and Instructional Expenses	3,123,200	3,745,519
170	(910) Miscellaneous Customer Service and Informational Expenses	15,904	99,133
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	135,712,011	136,012,327
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	78,097,396	75,687,733
182	(921) Office Supplies and Expenses	8,563,778	8,332,848
183	(Less) (922) Administrative Expenses Transferred-Credit	37,773,122	33,980,836
184	(923) Outside Services Employed	16,829,096	14,156,752
185	(924) Property Insurance	15,938,310	15,633,179
186	(925) Injuries and Damages	5,349,612	-23,490,203
187	(926) Employee Pensions and Benefits		
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	22,275,686	24,280,590
190	(929) (Less) Duplicate Charges-Cr.	5,386,124	7,469,667
191	(930.1) General Advertising Expenses	319	6,832
192	(930.2) Miscellaneous General Expenses	2,386,938	2,426,050
193	(931) Rents	4,960,462	6,140,970
194	TOTAL Operation (Enter Total of lines 181 thru 193)	111,242,351	81,724,248
195	Maintenance		
196	(935) Maintenance of General Plant	22,974,990	22,162,699
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	134,217,341	103,886,947
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	2,987,243,744	3,070,184,314

Schedule Page: 320 Line No.: 10 Column: b

Amount includes recovery of closure costs related to the Utah Mine Disposition offset in Account 501, Fuel expense and established in Account 182.3, Other regulatory assets.

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

Amended in accordance with Attachment H-2, Article IV of the Open Access Transmission Tariff.

Schedule Page: 320 Line No.: 102 Column: c

Represents the difference between actual expense for the period and the accruals charged to Account 569, Maintenance of structures, during the period.

Schedule Page: 320 Line No.: 110 Column: c

Amount includes reinstatement of a construction work in progress balance for which the construction was previously expected to be canceled.

Schedule Page: 320 Line No.: 135 Column: c

Amended in accordance with Attachment H-2, Article IV of the Open Access Transmission Tariff.

Schedule Page: 320 Line No.: 186 Column: c

Amount includes expected insurance recovery related to the Sanpete County, Utah rangeland fire.

Schedule Page: 320 Line No.: 187 Column: b

Pensions and benefits expense is associated with labor and generally charged to operations and maintenance expense and construction work in progress. During the years ended December 31, 2015 and 2014, pensions and benefits expense was $124,649,217 and $126,017,454, respectively.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	Power Purchases:					
2	3Degrees Group, Inc.	OS		NA	NA	NA
3	3Degrees Group, Inc.	OS		NA	NA	NA
4	Apple, Inc.	LU		NA	NA	NA
5	Arizona Electric Power Cooperative	SF		NA	NA	NA
6	Arizona Public Service Company	LF		NA	NA	NA
7	Arizona Public Service Company	SF		NA	NA	NA
8	Avista Corporation	SF		NA	NA	NA
9	BP Energy Company	SF		NA	NA	NA
10	Ballard Hog Farms Inc.	LU		0.03	0.03	0.03
11	Barclays Bank PLC	SF		NA	NA	NA
12	Basin Electric Power Cooperative	SF		NA	NA	NA
13	Beaver City Corporation	LF		NA	NA	NA
14	Bell Mountain Hydro, LLC	AD		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)	
							1
					19,800	19,800	2
					49,313	49,313	3
5,561				350,522		350,522	4
102,948				3,896,377		3,896,377	5
80,830				1,669,317		1,669,317	6
283,200				6,380,329	223,058	6,603,387	7
159,166				3,941,860	4,702	3,946,562	8
193,561				5,724,122		5,724,122	9
199			4,136	8,462		12,598	10
23,575				1,004,295		1,004,295	11
88,143				3,044,264		3,044,264	12
73				6,104		6,104	13
-1					683	683	14
11,948,954	4,930,109	4,919,231	73,100,375	620,673,305	-70,665,544	623,108,136	

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	Bell Mountain Hydro, LLC	LU		NA	NA	NA
2	Beryl Solar, LLC	LU		3	3	0.1
3	Big Top, LLC	LU		NA	NA	NA
4	Biomass One, L.P.	LU		NA	NA	NA
5	Birch Power Company, Inc.	LU		NA	NA	NA
6	Black Cap Solar, LLC	LU		NA	NA	NA
7	Black Hills Power, Inc.	SF		NA	NA	NA
8	Bonneville Power Administration	AD		NA	NA	NA
9	Bonneville Power Administration	LF		NA	NA	NA
10	Bonneville Power Administration	OS		NA	NA	NA
11	Bonneville Power Administration	SF		NA	NA	NA
12	Bourdet, Peter M.	LU		NA	NA	NA
13	Box Canyon Limited Partnership	LU		2	2.5	0.9
14	Brigham Young University - Idaho	IU		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)	
703				57,730		57,730	1
1,926			160,635	52,096		212,731	2
3,453				252,174		252,174	3
152,593				10,905,737	2,328,619	13,234,356	4
11,942				732,694		732,694	5
655				22,328		22,328	6
23,161				897,849		897,849	7
					16,710	16,710	8
					9,856	9,856	9
					131,597	131,597	10
583,849				14,387,781	30,140	14,417,921	11
130				4,390		4,390	12
9,815			188,432	1,279,861		1,468,293	13
13,105				502,560		502,560	14
11,948,954	4,930,109	4,919,231	73,100,375	620,673,305	-70,665,544	623,108,136	

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	Brookfield Energy Marketing L.P.	SF		NA	NA	NA
2	Butter Creek Power, LLC	LU		NA	NA	NA
3	C Drop Hydro, LLC	LU		NA	NA	NA
4	CDM Hydroelectric Company	LU		NA	NA	NA
5	California Independent System Operator	AD		NA	NA	NA
6	California Independent System Operator	SF		NA	NA	NA
7	Calpine Energy Services, L.P.	SF		NA	NA	NA
8	Cameron A. Curtiss	LU		NA	NA	NA
9	Cargill Power Markets, LLC	SF		NA	NA	NA
10	Cargill, Incorporated	LU		NA	NA	NA
11	Cedar Valley Solar, LLC	LU		5	2.9	0
12	Central Oregon Irrigation District	LU		4.6	4	3
13	Chevron U.S.A. Inc.	LU		NA	NA	NA
14	City of Albany	LU		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.
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7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
200				4,600		4,600	1
11,565				840,220		840,220	2
2,246				164,653		164,653	3
26,173				1,602,564		1,602,564	4
-2,545					-8,139	-8,139	5
17,343				1,185,382		1,185,382	6
133,500				4,377,875		4,377,875	7
49				3,576		3,576	8
336,404				10,341,255		10,341,255	9
6,030				445,104		445,104	10
			56	10		66	11
38,382			475,263	3,797,043		4,272,306	12
37,035				639,901		639,901	13
677				50,092		50,092	14
11,948,954	4,930,109	4,919,231	73,100,375	620,673,305	-70,665,544	623,108,136	

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

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

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

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

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	City of Anaheim	SF		NA	NA	NA
2	City of Astoria	LU		NA	NA	NA
3	City of Burbank	SF		NA	NA	NA
4	City of Hurricane	LF		NA	NA	NA
5	City of Lehi	AD		NA	NA	NA
6	City of Lehi	IF		NA	NA	NA
7	City of Portland, Water Bureau	LU		NA	NA	NA
8	City of Preston Idaho	LU		NA	NA	NA
9	City of Redding	SF		NA	NA	NA
10	Clatskanie People's Utility District	SF		NA	NA	NA
11	Commercial Energy Management Inc.	AD		NA	NA	NA
12	Commercial Energy Management Inc.	LU		NA	NA	NA
13	ConocoPhillips Company	OS		NA	NA	NA
14	ConocoPhillips Company	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)	
26				134		134	1
14				565		565	2
59,114				1,555,802		1,555,802	3
1,919				124,722		124,722	4
					-40	-40	5
308				343		343	6
123				9,054		9,054	7
3,070				174,566		174,566	8
220				6,500		6,500	9
2,610				106,296		106,296	10
12					-1,879	-1,879	11
1,009				56,212		56,212	12
					15,036	15,036	13
12,000				337,800		337,800	14
11,948,954	4,930,109	4,919,231	73,100,375	620,673,305	-70,665,544	623,108,136	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	Consolidated Irrigation Company	LU		NA	NA	NA
2	Cottonwood Hydro, LLC	IU		NA	NA	NA
3	Crook County Solar 1, LLC	LU		NA	NA	NA
4	Deschutes Valley Water District	LU		5.5	3.8	2.9
5	Deseret Generation & Transmission Coop	LF		100	99	91
6	Dorena Hydro, LLC	AD		NA	NA	NA
7	Dorena Hydro, LLC	LU		NA	NA	NA
8	Douglas County	LU		0.4	0.7	0.6
9	Douglas County, Inc.	LU		NA	NA	NA
10	Draper Irrigation Company	IU		NA	NA	NA
11	Dry Creek LLC	LU		NA	NA	NA
12	EDF Trading North America, LLC	SF		NA	NA	NA
13	eBay Inc.	LU		NA	NA	NA
14	El Paso Electric Company	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)	
496				9,410		9,410	1
3,608				246,040		246,040	2
1,255				43,177		43,177	3
27,228			542,509	3,351,762		3,894,271	4
511,279			16,306,446	10,629,321	4,239,640	31,175,407	5
299					14,715	14,715	6
7,941				580,234		580,234	7
4,045			46,665	558,581		605,246	8
7,202				173,973		173,973	9
161				9,252		9,252	10
8,704				496,595		496,595	11
834,463				27,709,663		27,709,663	12
916				62,410		62,410	13
20,770				484,322	1,494	485,816	14
11,948,954	4,930,109	4,919,231	73,100,375	620,673,305	-70,665,544	623,108,136	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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	Eugene Water & Electric Board	SF		NA	NA	NA
2	Eurus Combine Hills I, LLC	LU		NA	NA	NA
3	Evergreen BioPower, LLC	LU		NA	NA	NA
4	Exelon Generation Company, LLC	IF		NA	NA	NA
5	Exelon Generation Company, LLC	SF		NA	NA	NA
6	ExxonMobil Production Company	LU		NA	NA	NA
7	Falls Creek H.P. Limited Partnership	LU		2.7	2.7	0.9
8	Farm Power Misty Meadow, LLC	AD		NA	NA	NA
9	Farm Power Misty Meadow, LLC	LU		NA	NA	NA
10	Farmers Irrigation District	LU		NA	NA	NA
11	Fillmore City Corporation	LF		NA	NA	NA
12	Finley BioEnergy, LLC	LU		NA	NA	NA
13	Flathead Electric Cooperative, Inc.	LF		NA	NA	NA
14	Foote Creek II, LLC	LU		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.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
19,716				507,590		507,590	1
91,036				4,233,142		4,233,142	2
56,473				3,788,267		3,788,267	3
122,421				4,567,442		4,567,442	4
744,109				21,134,506		21,134,506	5
57				1,721		1,721	6
9,911			132,287	1,232,984		1,365,271	7
					286	286	8
3,213				235,765		235,765	9
19,836				1,383,584		1,383,584	10
182				19,680		19,680	11
24,260				1,793,975		1,793,975	12
379					8,800	8,800	13
5,157				102,298		102,298	14
11,948,954	4,930,109	4,919,231	73,100,375	620,673,305	-70,665,544	623,108,136	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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.
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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	Foote Creek III, LLC	LU		NA	NA	NA
2	Four Corners Windfarm, LLC	LU		NA	NA	NA
3	Four Mile Canyon Windfarm, LLC	LU		NA	NA	NA
4	George DeRuyter & Sons Dairy	LU		0.27	0.4	0.3
5	Georgetown Irrigation Company	LU		NA	NA	NA
6	Grand Valley Power	LF		NA	NA	NA
7	Granite Peak Solar, LLC	LU		3	2.9	0.7
8	Greenville Solar, LLC	LU		1.6	1.3	0
9	Gridforce Energy Management	AD		NA	NA	NA
10	Gridforce Energy Management	SF		NA	NA	NA
11	Harold Foster & Robert Walker	LU		NA	NA	NA
12	Hermiston Generating Company, L.P.	AD		NA	NA	NA
13	Hermiston Generating Company, L.P.	LU		229	229	177
14	Iberdrola Renewables, LLC	SF		NA	NA	NA
	Total					

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

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7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
62,479				1,372,923		1,372,923	1
25,626				1,859,588		1,859,588	2
23,104				1,681,155		1,681,155	3
2,399			8,184	76,579		84,763	4
2,047				123,310		123,310	5
34				8,608		8,608	6
1,693			61,705	53,286		114,991	7
99			43,448	4,214		47,662	8
1					20	20	9
33					690	690	10
902				35,525		35,525	11
					-12,762	-12,762	12
1,200,393			37,360,795	27,578,896	251,657	65,191,348	13
2,434,744				66,770,664		66,770,664	14
11,948,954	4,930,109	4,919,231	73,100,375	620,673,305	-70,665,544	623,108,136	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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.
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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	Idaho Falls, City of	AD		NA	NA	NA
2	Idaho Falls, City of	LU		NA	NA	NA
3	Idaho Power Company	OS		NA	NA	NA
4	Idaho Power Company	SF		NA	NA	NA
5	Intermountain Power Agency	LU		NA	NA	NA
6	J Bar 9 Ranch, Inc.	LU		NA	NA	NA
7	Jake Amy	LU		NA	NA	NA
8	Joseph Community Solar LLC	LU		NA	NA	NA
9	Kennecott Utah Copper LLC	LU		NA	NA	NA
10	Lacomb Irrigation District	LU		NA	NA	NA
11	Laho Solar, LLC	LU		3	3.5	1.2
12	Los Angeles Dept. of Water and Power	SF		NA	NA	NA
13	Lower Valley Energy, Inc.	IU		NA	NA	NA
14	Lower Valley Energy, Inc.	LU		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.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					-44,889	-44,889	1
40,781					2,601,032	2,601,032	2
300				3,300	-200	3,100	3
9,731				176,162	1,805	177,967	4
569,850				26,570,488		26,570,488	5
60				3,618		3,618	6
1,277				73,602		73,602	7
671				22,693		22,693	8
83,171				2,676,211		2,676,211	9
4,520				105,627	39,019	144,646	10
3,157			84,842	92,542		177,384	11
67,321				3,252,961		3,252,961	12
5,978				303,654		303,654	13
1,512				80,750		80,750	14
11,948,954	4,930,109	4,919,231	73,100,375	620,673,305	-70,665,544	623,108,136	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	Loyd Fery	LU		NA	NA	NA
2	Macquarie Energy LLC	SF		NA	NA	NA
3	Marsh Valley Hydro Electric Company	LU		NA	NA	NA
4	Meadow Creek Project Company LLC	LU		NA	NA	NA
5	Middle Fork Irrigation District	LU		NA	NA	NA
6	Milford Flat Solar, LLC	LU		NA	NA	NA
7	Mink Creek Hydro LLC	LU		NA	NA	NA
8	Monroe Hydro, LLC	LU		NA	NA	NA
9	Monsanto Company	IU		NA	NA	NA
10	Morgan City Corporation	LF		NA	NA	NA
11	Morgan Stanley Capital Group Inc.	SF		NA	NA	NA
12	Mountain Energy, Inc.	LU		NA	NA	NA
13	Mountain Wind Power II, LLC	LU		NA	NA	NA
14	Mountain Wind Power, LLC	LU		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)	
335				12,149		12,149	1
188,432				5,384,850		5,384,850	2
3,143				193,132		193,132	3
298,255				20,668,300		20,668,300	4
23,904				1,599,847		1,599,847	5
2,655				62,685		62,685	6
8,576				509,486		509,486	7
44				1,114		1,114	8
					19,806,635	19,806,635	9
9				814		814	10
517,655				22,665,837		22,665,837	11
40				2,936		2,936	12
183,055				11,908,767		11,908,767	13
140,487				7,899,282		7,899,282	14
11,948,954	4,930,109	4,919,231	73,100,375	620,673,305	-70,665,544	623,108,136	

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	Municipal Energy Agency of Nebraska	SF		NA	NA	NA
2	NaturEner Power Watch, LLC	SF		NA	NA	NA
3	Nevada Power Company	SF		NA	NA	NA
4	NextEra Energy Power Marketing, LLC	OS		NA	NA	NA
5	NextEra Energy Power Marketing, LLC	SF		NA	NA	NA
6	Nichols Gap Limited Partnership	LU		0.8	0.5	0.4
7	Nicholson's Sunny Bar Ranch	LU		NA	NA	NA
8	NorthWestern Corporation	OS		NA	NA	NA
9	NorthWestern Corporation	SF		NA	NA	NA
10	Nucor Corporation	IF		NA	NA	NA
11	O.J. Power Company	LU		NA	NA	NA
12	Obsidian Renewables, LLC	LU		NA	NA	NA
13	Oregon Environmental Industries, LLC	LU		NA	NA	NA
14	Oregon Institute of Technology	LU		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)	
9,889				434,279		434,279	1
4					70	70	2
54,621				1,960,549	72,510	2,033,059	3
					52,626	52,626	4
3,025				53,856		53,856	5
3,152			41,232	410,435		451,667	6
1,253				75,861		75,861	7
230				3,790		3,790	8
8,618				182,341	4,436	186,777	9
					6,273,000	6,273,000	10
310				15,397		15,397	11
946				32,475		32,475	12
19,622				1,310,511		1,310,511	13
1,130				22,068		22,068	14
11,948,954	4,930,109	4,919,231	73,100,375	620,673,305	-70,665,544	623,108,136	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	Oregon State University	LU		NA	NA	NA
2	Oregon Trail Windfarm, LLC	LU		NA	NA	NA
3	Pacific Canyon Windfarm, LLC	LU		NA	NA	NA
4	Paul Luckey	LU		NA	NA	NA
5	Pavant Solar, LLC	LU		NA	NA	NA
6	Platte River Power Authority	SF		NA	NA	NA
7	Portland General Electric Company	AD		NA	NA	NA
8	Portland General Electric Company	LF		NA	NA	NA
9	Portland General Electric Company	SF		NA	NA	NA
10	Power County Wind Park North, LLC	LU		NA	NA	NA
11	Power County Wind Park South, LLC	LU		NA	NA	NA
12	Powerex Corporation	SF		NA	NA	NA
13	Provo City Corporation	LF		NA	NA	NA
14	Public Service Company of Colorado	AD		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)	
103				3,063		3,063	1
22,916				1,663,604		1,663,604	2
17,293				1,261,458		1,261,458	3
136				4,854		4,854	4
1,392				29,961		29,961	5
2,880					70,965	70,965	6
					-23,485	-23,485	7
12,000					172,000	172,000	8
81,759				2,133,542	6,525	2,140,067	9
57,345				3,977,161		3,977,161	10
50,378				3,510,784		3,510,784	11
664,437				24,222,241		24,222,241	12
38				3,926		3,926	13
-20					-600	-600	14
11,948,954	4,930,109	4,919,231	73,100,375	620,673,305	-70,665,544	623,108,136	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	SF		NA	NA	NA
2	Public Service Company of New Mexico	SF		NA	NA	NA
3	PUD No. 1 of Chelan County	OS		NA	NA	NA
4	PUD No. 1 of Chelan County	SF		NA	NA	NA
5	PUD No. 1 of Clark County	SF		NA	NA	NA
6	PUD No. 1 of Cowlitz County	OS		NA	NA	NA
7	PUD No. 1 of Douglas County	AD		NA	NA	NA
8	PUD No. 1 of Douglas County	LF		NA	NA	NA
9	PUD No. 1 of Douglas County	LU		NA	NA	NA
10	PUD No. 1 of Douglas County	SF		NA	NA	NA
11	PUD No. 1 of Snohomish County	SF		NA	NA	NA
12	PUD No. 2 of Grant County	AD		NA	NA	NA
13	PUD No. 2 of Grant County	LU		NA	NA	NA
14	PUD No. 2 of Grant County	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)	
5,191				188,267		188,267	1
40,207				962,041	166	962,207	2
					8,570	8,570	3
16,595				507,838	1,554	509,392	4
12,882				293,551		293,551	5
					39,189	39,189	6
					-38,512	-38,512	7
66,010				2,224,195		2,224,195	8
228,377					3,577,732	3,577,732	9
50,707				1,179,745	363	1,180,108	10
65,137				1,327,762		1,327,762	11
					1,048,402	1,048,402	12
88,272					-2,932,610	-2,932,610	13
62,403				1,608,957	2,165	1,611,122	14
11,948,954	4,930,109	4,919,231	73,100,375	620,673,305	-70,665,544	623,108,136	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	Puget Sound Energy, Inc.	OS		NA	NA	NA
2	Puget Sound Energy, Inc.	SF		NA	NA	NA
3	RES Ag - Oak Lea LLC	LU		NA	NA	NA
4	Rainbow Energy Marketing Corporation	SF		NA	NA	NA
5	Rock River 1, LLC	LU		NA	NA	NA
6	Roseburg Forest Products Company	LU		NA	NA	NA
7	Roseburg LFG Energy, LLC	LU		NA	NA	NA
8	Rough & Ready Lumber Company	LU		NA	NA	NA
9	Roush Hydro Inc.	LU		NA	NA	NA
10	Sacramento Municipal Utility District	AD		NA	NA	NA
11	Sacramento Municipal Utility District	LF		NA	NA	NA
12	Sacramento Municipal Utility District	SF		NA	NA	NA
13	Salt River Project	SF		NA	NA	NA
14	Sand Ranch Windfarm, LLC	LU		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 (2) [ ] A Resubmission	/ /	End of 2015/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)	
					47,369	47,369	1
270,353				6,593,297	8,155	6,601,452	2
510				37,761		37,761	3
45,152				1,299,875		1,299,875	4
117,698				4,175,495		4,175,495	5
70,813				4,057,495		4,057,495	6
10,903				797,367		797,367	7
3,273				241,658		241,658	8
224				8,075		8,075	9
					146,723	146,723	10
218,998				4,601,148		4,601,148	11
1,300				28,200		28,200	12
258,231				8,371,220	7,084	8,378,304	13
21,302				1,552,444		1,552,444	14
11,948,954	4,930,109	4,919,231	73,100,375	620,673,305	-70,665,544	623,108,136	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	Santiam Water Control District	LU		0.2	0.2	0.2
2	Seattle City Light	SF		NA	NA	NA
3	Sempra Generation, LLC	SF		NA	NA	NA
4	Shell Energy North America (US), L.P.	SF		NA	NA	NA
5	Shiloh Warm Springs Ranch, LLC	LU		NA	NA	NA
6	Sierra Pacific Power Company	SF		NA	NA	NA
7	Sierra Pacific Power Company	SF		NA	NA	NA
8	Slate Creek Hydro Company, Inc.	LU		2.1	0.9	0.4
9	Solwatt LLC	LU		NA	NA	NA
10	South Utah Valley Electric	LF		NA	NA	NA
11	Southern California Edison Company	SF		NA	NA	NA
12	Spanish Fork Wind Park 2, LLC	LU		NA	NA	NA
13	Sprague Hydro LLC	LU		0.5	0.6	0.3
14	St. Anthony Hydro, LLC	AD		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.
1,490			13,632	155,041		168,673	1
124,257				2,786,929	2,909	2,789,838	2
216,135				5,150,092		5,150,092	3
447,571				12,424,516		12,424,516	4
977				60,027		60,027	5
203					4,267	4,267	6
130					3,044	3,044	7
3,218			55,638	379,496		435,134	8
825				27,794		27,794	9
40				2,851		2,851	10
9,694				199,328		199,328	11
45,915				2,302,612		2,302,612	12
3,089			53,288	397,860		451,148	13
					9,602	9,602	14
11,948,954	4,930,109	4,919,231	73,100,375	620,673,305	-70,665,544	623,108,136	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	St. Anthony Hydro, LLC	LU		NA	NA	NA
2	Stahlbush Island Farms, Inc.	IU		NA	NA	NA
3	SunE DB18, LLC	LU		2.9	2.8	1.5
4	SunE Solar XVII Project1, LLC	LU		2.6	3.7	0.7
5	SunE Solar XVII Project2, LLC	LU		2.6	3.4	0.6
6	SunE Solar XVII Project3, LLC	LU		2.4	2.4	0
7	Sunnyside Cogeneration Associates	LU		52	53	47
8	Swalley Irrigation District	LU		NA	NA	NA
9	TMF Biofuels, LLC	LU		NA	NA	NA
10	Tacoma Power	SF		NA	NA	NA
11	Talen Energy Marketing, LLC	SF		NA	NA	NA
12	Tata Chemicals (Soda Ash) Partners	LU		NA	NA	NA
13	Tenaska Power Services Co.	SF		NA	NA	NA
14	Tesoro Refining & Marketing Co, LLC	AD		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)	
3,547				185,385		185,385	1
1,131				23,391		23,391	2
5,845			287,929	247,554		535,483	3
1,571			114,371	64,086		178,457	4
1,610			115,058	65,746		180,804	5
228			27,106	8,219		35,325	6
418,218			10,869,286	17,161,671		28,030,957	7
2,332				172,663		172,663	8
33,294				2,299,085		2,299,085	9
136,485				3,604,656	1,425	3,606,081	10
100,278				2,506,563		2,506,563	11
3,629				108,732		108,732	12
14,082				596,608		596,608	13
					-552	-552	14
11,948,954	4,930,109	4,919,231	73,100,375	620,673,305	-70,665,544	623,108,136	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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.

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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	Tesoro Refining & Marketing Co, LLC	LU		NA	NA	NA
2	Tesoro Refining & Marketing Co, LLC	OS		NA	NA	NA
3	Thayn Hydro LLC	LU		0.3	0.4	0.3
4	The Confederated Tribe of Warm Springs	LU		NA	NA	NA
5	The Energy Authority, Inc.	SF		NA	NA	NA
6	The Town of the City of Buffalo	LU		0.2	0.2	0.2
7	Three Buttes Windpower, LLC	LU		NA	NA	NA
8	Three Sisters Irrigation District	AD		NA	NA	NA
9	Three Sisters Irrigation District	LU		NA	NA	NA
10	Threemile Canyon Wind I, LLC	LU		NA	NA	NA
11	Top of The World Wind Energy LLC	LU		NA	NA	NA
12	TransAlta Energy Marketing (U.S.) Inc.	SF		NA	NA	NA
13	TransCanada Energy Sales Ltd.	SF		NA	NA	NA
14	Tri-State Generation and Transmission	LF		25	25	22
	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)	
27,528				881,990		881,990	1
4,581				146,705		146,705	2
2,803			95,575	271,288		366,863	3
291				9,797		9,797	4
140,474				3,246,813		3,246,813	5
1,834			38,906	209,567		248,473	6
294,027				18,682,592		18,682,592	7
					1,026	1,026	8
2,101				78,724		78,724	9
19,540				1,453,247		1,453,247	10
570,069				37,624,530		37,624,530	11
929,972				29,649,861		29,649,861	12
400				10,000		10,000	13
113,780			5,916,000	3,581,794		9,497,794	14
11,948,954	4,930,109	4,919,231	73,100,375	620,673,305	-70,665,544	623,108,136	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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)	Average Monthly CP Demand (f)
1	Tri-State Generation and Transmission	SF		NA	NA	NA
2	Tucson Electric Power Company	SF		NA	NA	NA
3	Turlock Irrigation District	SF		NA	NA	NA
4	U.S. Dept of the Interior	LU		NA	NA	NA
5	UNS Electric, Inc.	SF		NA	NA	NA
6	US Magnesium LLC	LF		NA	NA	NA
7	United States Air Force at Hill Base	LU		NA	NA	NA
8	Utah Municipal Power Agency	IU		NA	NA	NA
9	Utah Municipal Power Agency	SF		NA	NA	NA
10	Utah Red Hills Renewable Park, LLC	LU		NA	NA	NA
11	Vitol Inc.	SF		NA	NA	NA
12	Wagon Trail, LLC	LU		NA	NA	NA
13	Ward Butte Windfarm, LLC	LU		NA	NA	NA
14	Wasatch Integrated Waste Mgmt District	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 (2) [ ] A Resubmission	/ /	End of 2015/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	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
(g)	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
8,406				229,487	26,913	256,400	1
75,194				2,018,956	133,865	2,152,821	2
2,000				47,300		47,300	3
14				865		865	4
3,528				97,117		97,117	5
					6,564,146	6,564,146	6
14,573				726,449		726,449	7
64,170				3,843,141		3,843,141	8
350				12,710		12,710	9
12,281				235,543		235,543	10
199,590				6,114,359		6,114,359	11
6,582				479,729		479,729	12
15,629				1,133,988		1,133,988	13
					19,968	19,968	14
11,948,954	4,930,109	4,919,231	73,100,375	620,673,305	-70,665,544	623,108,136	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	Wasatch Integrated Waste Mgmt District	LU		0.5	0.4	0.1
2	Weber County	LU		NA	NA	NA
3	Western Area Power Administration	AD		NA	NA	NA
4	Western Area Power Administration	LF		NA	NA	NA
5	Western Area Power Administration	SF		NA	NA	NA
6	Western Area Power Administration	SF		NA	NA	NA
7	Wolverine Creek Energy, LLC	LU		NA	NA	NA
8	Yakima-Tieton Irrigation District	LU		0.9	1.4	1.3
9	Oregon Solar Incentive	LU		NA	NA	NA
10	Settlements/Reserves			NA	NA	NA
11	Netting - Bookouts			NA	NA	NA
12	Netting - Trading			NA	NA	NA
13	CA Greenhouse Gas Allowance Purchases			NA	NA	NA
14	Fair value adjustment amortization			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)	
1,136			31,209	67,980		99,189	1
2,741				140,889		140,889	2
					141	141	3
20,396					674,347	674,347	4
7,253				318,658	53	318,711	5
10,864					350,500	350,500	6
142,899				8,285,296		8,285,296	7
7,916			25,742	296,229		321,971	8
10,022				341,879		341,879	9
					-2,071,120	-2,071,120	10
-5,859,001					-161,672,255	-161,672,255	11
					-496,450	-496,450	12
					3,107,838	3,107,838	13
					-2,125,853	-2,125,853	14
11,948,954	4,930,109	4,919,231	73,100,375	620,673,305	-70,665,544	623,108,136	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	Net Power Cost Deferrals			NA	NA	NA
2	Accrual			NA	NA	NA
3						
4	Power Exchanges:					
5	Arizona Public Service Company	EX	307	NA	NA	NA
6	Avista Corporation	EX	T-13	NA	NA	NA
7	Basin Electric Power Cooperative	AD	T-11	NA	NA	NA
8	Basin Electric Power Cooperative	EX	T-11	NA	NA	NA
9	Basin Electric Power Cooperative	EX	T-11	NA	NA	NA
10	Bonneville Power Administration	AD	237	NA	NA	NA
11	Bonneville Power Administration	AD	T-11	NA	NA	NA
12	Bonneville Power Administration	AD	T-12	NA	NA	NA
13	Bonneville Power Administration	AD	T-12	NA	NA	NA
14	Bonneville Power Administration	EX	237	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)	
					39,311,037	39,311,037	1
					12,880,840	12,880,840	2
							3
							4
	571,029	571,373			2,330,000	2,330,000	5
	1,570						6
	2				38,016	38,016	7
					-88	-88	8
	7,285	598			228,148	228,148	9
					-312,987	-312,987	10
	2,129	-425			69,969	69,969	11
	-816				-22,958	-22,958	12
					-525,000	-525,000	13
		12,550			-31,379	-31,379	14
11,948,954	4,930,109	4,919,231	73,100,375	620,673,305	-70,665,544	623,108,136	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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	Bonneville Power Administration	EX	256	NA	NA	NA
2	Bonneville Power Administration	EX	519	NA	NA	NA
3	Bonneville Power Administration	EX	T-11	NA	NA	NA
4	Bonneville Power Administration	EX	T-12	NA	NA	NA
5	Bonneville Power Administration	EX	T-13	NA	NA	NA
6	California Independent System Operator	AD	T-11	NA	NA	NA
7	California Independent System Operator	AD	T-12	NA	NA	NA
8	California Independent System Operator	EX	T-11	NA	NA	NA
9	California Independent System Operator	EX	T-12	NA	NA	NA
10	Cargill Power Markets, LLC	AD	T-11	NA	NA	NA
11	Cargill Power Markets, LLC	EX	T-11	NA	NA	NA
12	City of Redding	EX	364	NA	NA	NA
13	Constellation Energy Commodities Group	AD	T-11	NA	NA	NA
14	Deseret Generation & Transmission Coop	AD	280	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)	
	936	936			-7,488	-7,488	1
	85,435	85,728			-110,953	-110,953	2
	22,389	4,127			546,521	546,521	3
	6,754				135,269	135,269	4
	258,941	7,329					5
					-5,341,762	-5,341,762	6
					5,537,401	5,537,401	7
					1,539,106	1,539,106	8
	222,654	977,188			-23,996,507	-23,996,507	9
	-15	-251			6,529	6,529	10
	4,388	4,694			-28,481	-28,481	11
	103,027	103,499			17,630	17,630	12
	676	831			31,985	31,985	13
	451	1,023			15,222	15,222	14
11,948,954	4,930,109	4,919,231	73,100,375	620,673,305	-70,665,544	623,108,136	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	Deseret Generation & Transmission Coop	EX	280	NA	NA	NA
2	Deseret Generation & Transmission Coop	EX	280	NA	NA	NA
3	EDF Trading North America, LLC	EX	T-11	NA	NA	NA
4	Emerald People's Utility District	EX	351	NA	NA	NA
5	Eugene Water & Electric Board	EX	T-12	NA	NA	NA
6	Exelon Generation Company, LLC	EX	T-11	NA	NA	NA
7	Iberdrola Renewables, LLC	AD	T-11	NA	NA	NA
8	Iberdrola Renewables, LLC	EX	T-11	NA	NA	NA
9	Idaho Power Company	AD	T-11	NA	NA	NA
10	Idaho Power Company	EX	380	NA	NA	NA
11	Idaho Power Company	EX	T-11	NA	NA	NA
12	J.P. Morgan Ventures Energy Corp	AD	T-11	NA	NA	NA
13	J.P. Morgan Ventures Energy Corp	EX	T-11	NA	NA	NA
14	Los Angeles Dept. of Water & Power	EX	OV-1	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)	
	292				10,103	10,103	1
	191,711	171,954			273,345	273,345	2
	2,323	2,633			-12,862	-12,862	3
		763			-19,074	-19,074	4
	15,537	15,482			3,605	3,605	5
	139,172	83,122			859,318	859,318	6
	478	1,670			-54,646	-54,646	7
	121,344	145,931			-987,858	-987,858	8
	-7,380	-8,578			-45	-45	9
	278,322	163,504					10
	120	85			1,001	1,001	11
	54	-255			174	174	12
	23,081	21,295			-61,222	-61,222	13
	4,038				255,246	255,246	14
11,948,954	4,930,109	4,919,231	73,100,375	620,673,305	-70,665,544	623,108,136	

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	Macquarie Energy LLC	AD	T-11	NA	NA	NA
2	Macquarie Energy LLC	EX	T-11	NA	NA	NA
3	Milford Wind Corridor Phase I, LLC	EX	OV-1	NA	NA	NA
4	Milford Wind Corridor Phase II, LLC	EX	OV-1	NA	NA	NA
5	Morgan Stanley Capital Group Inc.	AD	T-11	NA	NA	NA
6	Morgan Stanley Capital Group Inc.	EX	T-11	NA	NA	NA
7	Nevada Power Company	AD	T-11	NA	NA	NA
8	Nevada Power Company	EX	T-11	NA	NA	NA
9	NextEra Energy Power Marketing, LLC	AD	T-11	NA	NA	NA
10	NextEra Energy Power Marketing, LLC	EX	T-11	NA	NA	NA
11	Noble Americas Energy Solutions LLC	AD	T-11	NA	NA	NA
12	Noble Americas Energy Solutions LLC	AD	T-11	NA	NA	NA
13	Noble Americas Energy Solutions LLC	EX	T-11	NA	NA	NA
14	NorthWestern Corporation	EX	160	NA	NA	NA
	Total					

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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)	
	-637	2,525			607	607	1
	25	25			144	144	2
		2,651			-165,628	-165,628	3
		1,387			-89,619	-89,619	4
	-725	78			-2,473	-2,473	5
	80,882	81,126			-84,248	-84,248	6
	-171	-171			-7	-7	7
	235	235			1	1	8
	17,460	6,260			342,086	342,086	9
	173,749	97,477			2,422,650	2,422,650	10
	-4	5			-145	-145	11
	5	238			-71	-71	12
	25,291	216			740,371	740,371	13
	4,835						14
11,948,954	4,930,109	4,919,231	73,100,375	620,673,305	-70,665,544	623,108,136	

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2015/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.

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Portland General Electric Company	AD	T-11	NA	NA	NA
2	Portland General Electric Company	EX	T-11	NA	NA	NA
3	Portland General Electric Company	EX	T-13	NA	NA	NA
4	Powerex Corporation	AD	T-11	NA	NA	NA
5	Powerex Corporation	EX	T-11	NA	NA	NA
6	Public Service Company of Colorado	EX	319	NA	NA	NA
7	Public Service Company of Colorado	EX	334	NA	NA	NA
8	PUD No. 1 of Cowlitz County	EX	442	NA	NA	NA
9	Sacramento Municipal Utility District	AD	T-11	NA	NA	NA
10	Sacramento Municipal Utility District	EX	T-11	NA	NA	NA
11	Seattle City Light	AD	T-12	NA	NA	NA
12	Seattle City Light	EX	T-12	NA	NA	NA
13	Shell Energy North America (US), L.P.	AD	T-11	NA	NA	NA
14	Shell Energy North America (US), L.P.	EX	T-11	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.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
	92	-55			-302	-302	1
	1,934	1,945			6,821	6,821	2
	154,195	153,039					3
	8,860	6,796			90,302	90,302	4
	60,910	60,664			32,632	32,632	5
	2,435						6
	1,313,999	1,309,193			5,400,000	5,400,000	7
	181,567	207,238					8
	-671	-828					9
	348	348					10
		-280			11,480	11,480	11
	309,464	298,647			-239,210	-239,210	12
	1,027	-280			21,119	21,119	13
	3,392	6,432			-90,390	-90,390	14
11,948,954	4,930,109	4,919,231	73,100,375	620,673,305	-70,665,544	623,108,136	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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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LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Southern California Edison Company	AD	T-11	NA	NA	NA
2	Southern California Edison Company	EX	T-11	NA	NA	NA
3	Southern CA Public Power Authority	EX	T-11	NA	NA	NA
4	State of South Dakota	EX	T-11	NA	NA	NA
5	Talen Energy Marketing, LLC	AD	T-11	NA	NA	NA
6	Talen Energy Marketing, LLC	EX	T-11	NA	NA	NA
7	The Energy Authority, Inc.	AD	T-11	NA	NA	NA
8	The Energy Authority, Inc.	EX	T-11	NA	NA	NA
9	Thermo No. 1 BE-01, LLC	AD	T-11	NA	NA	NA
10	Thermo No. 1 BE-01, LLC	EX	T-11	NA	NA	NA
11	TransAlta Energy Marketing (U.S.) Inc.	AD	T-11	NA	NA	NA
12	TransAlta Energy Marketing (U.S.) Inc.	EX	T-11	NA	NA	NA
13	Tri-State Generation and Transmission	AD	319	NA	NA	NA
14	Tri-State Generation and Transmission	AD	T-11	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)	
	3,375	1,852			41,627	41,627	1
	185,071	136,068			728,313	728,313	2
	275	692			-10,366	-10,366	3
	27	43			-644	-644	4
	-10,913	-10,913			-24	-24	5
	1,857	1,857			-14,797	-14,797	6
	-30	15			-1,727	-1,727	7
	5,509	5,509			-27,245	-27,245	8
	375	357			-1,087	-1,087	9
	2,221	2,143			592	592	10
	5,188	3,497			-151	-151	11
	34,327	33,990			-109,203	-109,203	12
					-16,843	-16,843	13
	866	-233			27,349	27,349	14
11,948,954	4,930,109	4,919,231	73,100,375	620,673,305	-70,665,544	623,108,136	

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	Tri-State Generation and Transmission	EX	319	NA	NA	NA
2	Tri-State Generation and Transmission	EX	T-11	NA	NA	NA
3	Utah Associated Municipal Power	AD	T-11	NA	NA	NA
4	Utah Associated Municipal Power	AD	T-11	NA	NA	NA
5	Utah Associated Municipal Power	EX	T-11	NA	NA	NA
6	Utah Associated Municipal Power	EX	T-11	NA	NA	NA
7	Utah Municipal Power Agency	AD	T-11	NA	NA	NA
8	Utah Municipal Power Agency	AD	T-11	NA	NA	NA
9	Utah Municipal Power Agency	EX	T-11	NA	NA	NA
10	Utah Municipal Power Agency	EX	T-11	NA	NA	NA
11	Warm Springs Power Enterprises	EX	T-11	NA	NA	NA
12	Western Area Power Administration	AD	LAS-4	NA	NA	NA
13	Western Area Power Administration	EX	LAS-4	NA	NA	NA
14	Imbalance Energy Accrual	EX	T-11	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 (2) [ ] A Resubmission	/ /	End of 2015/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)	
	2,435				-15,184	-15,184	1
	45,206	5,019			1,387,662	1,387,662	2
	-6,303	-1,697			-166,860	-166,860	3
		-9,821			284,281	284,281	4
	184,426	111,858			2,409,957	2,409,957	5
	20,830				5,405	5,405	6
	-64	-15			-5,379	-5,379	7
	13				350	350	8
	48,619	3,734			1,524,958	1,524,958	9
	67				2,640	2,640	10
	6,845	4,024			41,832	41,832	11
	544	3,142			-123,607	-123,607	12
	4,919	26,393			-475,578	-475,578	13
					69,301	69,301	14
11,948,954	4,930,109	4,919,231	73,100,375	620,673,305	-70,665,544	623,108,136	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	System Deviation	NA		NA	NA	NA
2						
3						
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)	
-8,439							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
11,948,954	4,930,109	4,919,231	73,100,375	620,673,305	-70,665,544	623,108,136	

Schedule Page: 326 Line No.: 2 Column: b
Secondary, economy and/or non-firm.
Schedule Page: 326 Line No.: 2 Column: l
Purchase of renewable energy credit certificates for Oregon renewable portfolio standard requirements.
Schedule Page: 326 Line No.: 3 Column: b
Secondary, economy and/or non-firm.
Schedule Page: 326 Line No.: 3 Column: l
Purchase of renewable energy credit certificates for California renewable portfolio standard requirements.
Schedule Page: 326 Line No.: 6 Column: b
Arizona Public Service Company - contract termination date: October 31, 2020.
Schedule Page: 326 Line No.: 7 Column: l
Line loss.
Schedule Page: 326 Line No.: 8 Column: l
Reserve share.
Schedule Page: 326 Line No.: 13 Column: b
Under Electric Service Agreement subject to termination upon timely notification.
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.: 4 Column: l
Non-generation agreement.
Schedule Page: 326.1 Line No.: 6 Column: a
PacifiCorp has an agreement with Citizens Asset Finance, Inc. to lease the Black Cap Solar generating facility. The lease has a 16-year term from October 2012 to October 2028 and is accounted for as an operating lease.
Schedule Page: 326.1 Line No.: 8 Column: b
Settlement adjustment.
Schedule Page: 326.1 Line No.: 8 Column: l
Ancillary services.
Schedule Page: 326.1 Line No.: 9 Column: b
Bonneville Power Administration - contract termination date: 30 days written notice.
Schedule Page: 326.1 Line No.: 9 Column: l
Ancillary services.
Schedule Page: 326.1 Line No.: 10 Column: b
Secondary, economy and/or non-firm.
Schedule Page: 326.1 Line No.: 10 Column: l
Ancillary services.
Schedule Page: 326.1 Line No.: 11 Column: l
Reserve share.
Schedule Page: 326.2 Line No.: 5 Column: a
This footnote applies to all occurrences of "California Independent System Operator" on pages 326-327. Complete name is California Independent System Operator Corporation.
Schedule Page: 326.2 Line No.: 5 Column: b
Settlement adjustment.
Schedule Page: 326.2 Line No.: 5 Column: l
Settlement adjustment.
Schedule Page: 326.3 Line No.: 4 Column: b
City of Hurricane - contract termination date: August 31, 2017.
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.: 7 Column: a
This footnote applies to all occurrences of "City of Portland, Water Bureau" on pages 326-327. Complete name is City of Portland, Portland Water Bureau.

Schedule Page: 326.3 Line No.: 11 Column: b
Settlement adjustment.

Schedule Page: 326.3 Line No.: 11 Column: l
Settlement adjustment.

Schedule Page: 326.3 Line No.: 13 Column: b
Secondary, economy and/or non-firm.

Schedule Page: 326.3 Line No.: 13 Column: l
Purchase of renewable energy credit certificates for Oregon renewable portfolio standard requirements.

Schedule Page: 326.4 Line No.: 5 Column: a
This footnote applies to all occurrences of "Deseret Generation & Transmission Coop" on pages 326-327. Complete name is Deseret Generation and Transmission Co-operative.

Schedule Page: 326.4 Line No.: 5 Column: b
Deseret Generation and Transmission Co-operative - contract termination date: September 30, 2024.

Schedule Page: 326.4 Line No.: 5 Column: l
Reimbursement to counterparty for operation and maintenance costs at coal fired generating facility located in Vernal, Utah.

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.: 14 Column: l
Line loss.

Schedule Page: 326.5 Line No.: 8 Column: b
Settlement adjustment.

Schedule Page: 326.5 Line No.: 8 Column: l
Settlement adjustment.

Schedule Page: 326.5 Line No.: 11 Column: b
Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.5 Line No.: 13 Column: b
Flathead Electric Cooperative, Inc. - contract termination date: September 30, 2016.

Schedule Page: 326.5 Line No.: 13 Column: l
Line loss.

Schedule Page: 326.6 Line No.: 6 Column: b
Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.6 Line No.: 9 Column: b
Settlement adjustment.

Schedule Page: 326.6 Line No.: 9 Column: l
Reserve share.

Schedule Page: 326.6 Line No.: 10 Column: l
Reserve share.

Schedule Page: 326.6 Line No.: 12 Column: a
This footnote applies to all occurrences of "Hermiston Generating Company, L.P." on pages 326-327. 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 (b) in this Form No. 1 for further information on the Hermiston Generating Plant.

Schedule Page: 326.6 Line No.: 12 Column: b
Settlement adjustment.

Schedule Page: 326.6 Line No.: 12 Column: l
On peak incentive, supplemental dispatch efficiency expense, start-up charges and committee settlements.

Schedule Page: 326.6 Line No.: 13 Column: l
On peak incentive, supplemental dispatch efficiency expense, start-up charges and committee settlements.

Schedule Page: 326.7 Line No.: 1 Column: b
Settlement adjustment.

Schedule Page: 326.7 Line No.: 1 Column: l
Labor, equipment and administration fees associated with hydro project in Idaho Falls, Idaho.

Schedule Page: 326.7 Line No.: 2 Column: l
Labor, equipment and administration fees associated with hydro project in Idaho Falls, Idaho.

Schedule Page: 326.7 Line No.: 3 Column: b
Secondary, economy and/or non-firm.

Schedule Page: 326.7 Line No.: 3 Column: l
Line loss settlement over delivery.

Schedule Page: 326.7 Line No.: 4 Column: l
Reserve share.

Schedule Page: 326.7 Line No.: 10 Column: l
Fixed annual payment.

Schedule Page: 326.7 Line No.: 12 Column: a
This footnote applies to all occurrences of "Los Angeles Dept. of Water & Power" on pages 326-327. Complete name is Los Angeles Department of Water and Power.

Schedule Page: 326.8 Line No.: 9 Column: l
Compensation for interruptible service and operating reserves.

Schedule Page: 326.8 Line No.: 10 Column: b
Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.9 Line No.: 2 Column: l
Reserve share.

Schedule Page: 326.9 Line No.: 3 Column: a
This footnote applies to all occurrences of "Nevada Power Company" on pages 326-327. Nevada Power Company is a principal subsidiary of NV Energy, Inc., which is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company, PacifiCorp's indirect parent company.

Schedule Page: 326.9 Line No.: 3 Column: l
Line loss.

Schedule Page: 326.9 Line No.: 4 Column: b
Secondary, economy and/or non-firm.

Schedule Page: 326.9 Line No.: 4 Column: l
Purchase of renewable energy credit certificates for Oregon renewable portfolio standard requirements.

Schedule Page: 326.9 Line No.: 8 Column: b
Secondary, economy and/or non-firm.

Schedule Page: 326.9 Line No.: 9 Column: l
Reserve share.

Schedule Page: 326.9 Line No.: 10 Column: l
Ancillary services.

Schedule Page: 326.10 Line No.: 6 Column: l
Line loss.

Schedule Page: 326.10 Line No.: 7 Column: b
Settlement adjustment.

Schedule Page: 326.10 Line No.: 7 Column: l

Operation expense plus amortization of unrecovered costs of Cove Project.

Schedule Page: 326.10 Line No.: 8 Column: b

Portland General Electric Company - contract termination date: terminates when the Round Butte project is no longer operating for power production purposes.

Schedule Page: 326.10 Line No.: 8 Column: l

Operation expense plus amortization of unrecovered costs of Cove Project.

Schedule Page: 326.10 Line No.: 9 Column: l

Reserve share.

Schedule Page: 326.10 Line No.: 13 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.10 Line No.: 14 Column: b

Settlement adjustment.

Schedule Page: 326.10 Line No.: 14 Column: l

Settlement adjustment.

Schedule Page: 326.11 Line No.: 2 Column: l

Line loss.

Schedule Page: 326.11 Line No.: 3 Column: a

This footnote applies to all occurrences of "PUD No. 1 of Chelan County" on pages 326-327. Complete name is Public Utility District No. 1 of Chelan County.

Schedule Page: 326.11 Line No.: 3 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.11 Line No.: 3 Column: l

Purchase of renewable energy credit certificates for Oregon renewable portfolio standard requirements.

Schedule Page: 326.11 Line No.: 4 Column: l

Reserve share.

Schedule Page: 326.11 Line No.: 5 Column: a

This footnote applies to all occurrences of "PUD No. 1 of Clark County" on pages 326-327. Complete name is Public Utility District No. 1 of Clark County.

Schedule Page: 326.11 Line No.: 6 Column: a

This footnote applies to all occurrences of "PUD No. 1 of Cowlitz County" on pages 326-327. Complete name is Public Utility District No. 1 of Cowlitz County.

Schedule Page: 326.11 Line No.: 6 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.11 Line No.: 6 Column: l

Liability associated with paper pond at hydro facility located on the Lewis River in the state of Washington.

Schedule Page: 326.11 Line No.: 7 Column: a

This footnote applies to all occurrences of "PUD No. 1 of Douglas County" on pages 326-327. Complete name is Public Utility District No. 1 of Douglas County.

Schedule Page: 326.11 Line No.: 7 Column: b

Settlement adjustment.

Schedule Page: 326.11 Line No.: 7 Column: l

Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.11 Line No.: 8 Column: b

Public Utility District No. 1 of Douglas County - contract termination date: August 31, 2018.

Schedule Page: 326.11 Line No.: 9 Column: l

Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.11 Line No.: 10 Column: l

Reserve share.

Schedule Page: 326.11 Line No.: 11 Column: a

This footnote applies to all occurrences of "PUD No. 1 of Snohomish County" on pages 326-327. Complete name is Public Utility District No. 1 of Snohomish County.

Schedule Page: 326.11 Line No.: 12 Column: a
This footnote applies to all occurrences of "PUD No. 2 of Grant County" on pages 326-327. Complete name is Public Utility District No. 2 of Grant County.

Schedule Page: 326.11 Line No.: 12 Column: b
Settlement adjustment.

Schedule Page: 326.11 Line No.: 12 Column: l
Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.11 Line No.: 13 Column: l
Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.11 Line No.: 14 Column: l
Reserve share.

Schedule Page: 326.12 Line No.: 1 Column: b
Secondary, economy and/or non-firm.

Schedule Page: 326.12 Line No.: 1 Column: l
Purchase of renewable energy credit certificates for Oregon renewable portfolio standard requirements.

Schedule Page: 326.12 Line No.: 2 Column: l
Reserve share.

Schedule Page: 326.12 Line No.: 10 Column: b
Settlement adjustment.

Schedule Page: 326.12 Line No.: 10 Column: l
Settlement adjustment.

Schedule Page: 326.12 Line No.: 11 Column: b
Sacramento Municipal Utility District - contract termination date: December 31, 2015.

Schedule Page: 326.12 Line No.: 13 Column: l
Line loss.

Schedule Page: 326.13 Line No.: 2 Column: l
Reserve share.

Schedule Page: 326.13 Line No.: 6 Column: a
This footnote applies to all occurrences of "Sierra Pacific Power Company" on pages 326-327. Sierra Pacific Power Company is a principal subsidiary of NV Energy, Inc., which is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company, PacifiCorp's indirect parent company.

Schedule Page: 326.13 Line No.: 6 Column: l
Reserve share.

Schedule Page: 326.13 Line No.: 7 Column: l
Line loss.

Schedule Page: 326.13 Line No.: 10 Column: a
This footnote applies to all occurrences of "South Utah Valley Electric" on pages 326-327. Complete name is South Utah Valley Electric Service District.

Schedule Page: 326.13 Line No.: 10 Column: b
Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.13 Line No.: 14 Column: b
Settlement adjustment.

Schedule Page: 326.13 Line No.: 14 Column: l
Settlement adjustment.

Schedule Page: 326.14 Line No.: 10 Column: l
Reserve share.

Schedule Page: 326.14 Line No.: 14 Column: a
This footnote applies to all occurrences of "Tesoro Refining & Marketing Co, LLC" on pages 326-327. Complete name is Tesoro Refining & Marketing Company, LLC.

Schedule Page: 326.14 Line No.: 14 Column: b
Settlement adjustment.

Schedule Page: 326.14 Line No.: 14 Column: l

Settlement adjustment.

Schedule Page: 326.15 Line No.: 2 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.15 Line No.: 4 Column: a

This footnote applies to all occurrences of "The Confederated Tribe of Warm Springs" on pages 326-327. Complete name is The Confederated Tribe of Warm Springs Utilities.

Schedule Page: 326.15 Line No.: 8 Column: b

Settlement adjustment.

Schedule Page: 326.15 Line No.: 8 Column: l

Settlement adjustment.

Schedule Page: 326.15 Line No.: 14 Column: a

This footnote applies to all occurrences of "Tri-State Generation and Transmission" on pages 326-327. Complete name is Tri-State Generation and Transmission Association, Inc.

Schedule Page: 326.15 Line No.: 14 Column: b

Tri-State Generation and Transmission Association, Inc. - contract termination date: December 31, 2020.

Schedule Page: 326.16 Line No.: 1 Column: l

Line loss.

Schedule Page: 326.16 Line No.: 2 Column: l

Line loss.

Schedule Page: 326.16 Line No.: 4 Column: a

This footnote applies to all occurrences of "U.S. Dept of the Interior" on pages 326-327. Complete name is U.S. Department of the Interior - Bureau of Land Management.

Schedule Page: 326.16 Line No.: 6 Column: b

US Magnesium LLC - contract termination date: December 31, 2017.

Schedule Page: 326.16 Line No.: 6 Column: l

Ancillary services.

Schedule Page: 326.16 Line No.: 7 Column: a

This footnote applies to all occurrences of "United States Air Force at Hill Base" on pages 326-327. Complete name is United States Air Force at Hill Air Force Base.

Schedule Page: 326.16 Line No.: 8 Column: a

This footnote applies to all occurrences of "Utah Associated Municipal Power Agency" on pages 326-327. Complete name is Utah Associated Municipal Power Systems.

Schedule Page: 326.16 Line No.: 14 Column: a

This footnote applies to all occurrences of "Wasatch Integrated Waste Mgmt District" on pages 326-327. Complete name is Wasatch Integrated Waste Management District.

Schedule Page: 326.16 Line No.: 14 Column: b

Settlement adjustment.

Schedule Page: 326.16 Line No.: 14 Column: l

Settlement adjustment.

Schedule Page: 326.17 Line No.: 3 Column: b

Settlement adjustment.

Schedule Page: 326.17 Line No.: 3 Column: l

Line loss.

Schedule Page: 326.17 Line No.: 4 Column: b

Western Area Power Administration - contract termination date: May 31, 2022.

Schedule Page: 326.17 Line No.: 4 Column: l

Line loss.

Schedule Page: 326.17 Line No.: 5 Column: l

Reserve share.

Schedule Page: 326.17 Line No.: 6 Column: l

Line loss.

Schedule Page: 326.17 Line No.: 10 Column: l

Settlement associated with insufficient line loss compensation in the past.

Schedule Page: 326.17 Line No.: 11 Column: l
Reflects transactions that did not physically settle.

Schedule Page: 326.17 Line No.: 12 Column: l
Reflects transactions that did not physically settle.

Schedule Page: 326.17 Line No.: 13 Column: l
Purchases of greenhouse gas allowances for compliance with the California Air Resources Board greenhouse gas cap-and-trade program.

Schedule Page: 326.17 Line No.: 14 Column: a
Purchase power agreement fair value adjustment amortization related to the acquisition of Eagle Mountain City, a Utah municipal corporation.

Schedule Page: 326.17 Line No.: 14 Column: l
Amortization of a purchase power agreement adjusted to fair value as part of a service territory acquisition.

Schedule Page: 326.18 Line No.: 1 Column: l
Deferrals and associated amortization under various energy cost adjustment mechanisms.

Schedule Page: 326.18 Line No.: 2 Column: l
Represents the difference between actual purchase expenses for the period as reflected on the individual line items within this schedule and the accruals charged to Account 555, Purchased power, during this period.

Schedule Page: 326.18 Line No.: 5 Column: l
Exchange energy expense.

Schedule Page: 326.18 Line No.: 7 Column: b
Settlement adjustment.

Schedule Page: 326.18 Line No.: 7 Column: l
PacifiCorp imbalance energy service for others.

Schedule Page: 326.18 Line No.: 8 Column: l
Imbalance energy.

Schedule Page: 326.18 Line No.: 9 Column: l
PacifiCorp imbalance energy service for others.

Schedule Page: 326.18 Line No.: 10 Column: b
Settlement adjustment.

Schedule Page: 326.18 Line No.: 10 Column: l
Storage and exchange charges.

Schedule Page: 326.18 Line No.: 11 Column: b
Settlement adjustment.

Schedule Page: 326.18 Line No.: 11 Column: l
PacifiCorp imbalance energy service for others.

Schedule Page: 326.18 Line No.: 12 Column: b
Settlement adjustment.

Schedule Page: 326.18 Line No.: 12 Column: l
Imbalance energy.

Schedule Page: 326.18 Line No.: 13 Column: b
Settlement adjustment.

Schedule Page: 326.18 Line No.: 13 Column: l
Storage and exchange charges.

Schedule Page: 326.18 Line No.: 14 Column: l
Storage and exchange charges.

Schedule Page: 326.19 Line No.: 1 Column: l
Storage and exchange charges.

Schedule Page: 326.19 Line No.: 2 Column: l
Storage and exchange charges.

Schedule Page: 326.19 Line No.: 3 Column: l
PacifiCorp imbalance energy service for others.

Schedule Page: 326.19 Line No.: 4 Column: l

Imbalance energy.

Schedule Page: 326.19 Line No.: 6 Column: b
Settlement adjustment.

Schedule Page: 326.19 Line No.: 6 Column: l
Energy Imbalance Market entity settlements.

Schedule Page: 326.19 Line No.: 7 Column: b
Settlement adjustment.

Schedule Page: 326.19 Line No.: 7 Column: l
Energy Imbalance Market participating resource settlements.

Schedule Page: 326.19 Line No.: 8 Column: l
Energy Imbalance Market entity settlements.

Schedule Page: 326.19 Line No.: 9 Column: l
Energy Imbalance Market participating resource settlements.

Schedule Page: 326.19 Line No.: 10 Column: b
Settlement adjustment.

Schedule Page: 326.19 Line No.: 10 Column: l
PacifiCorp imbalance energy service for others.

Schedule Page: 326.19 Line No.: 11 Column: l
PacifiCorp imbalance energy service for others.

Schedule Page: 326.19 Line No.: 12 Column: l
Exchange energy expense.

Schedule Page: 326.19 Line No.: 13 Column: a
This footnote applies to all occurrences of "Constellation Energy Commodities Group" on pages 326-327. Complete name is Constellation Energy Commodities Group, Inc.

Schedule Page: 326.19 Line No.: 13 Column: b
Settlement adjustment.

Schedule Page: 326.19 Line No.: 13 Column: l
PacifiCorp imbalance energy service for others.

Schedule Page: 326.19 Line No.: 14 Column: b
Settlement adjustment.

Schedule Page: 326.19 Line No.: 14 Column: l
PacifiCorp imbalance energy service for others.

Schedule Page: 326.20 Line No.: 1 Column: l
Imbalance energy.

Schedule Page: 326.20 Line No.: 2 Column: l
PacifiCorp imbalance energy service for others.

Schedule Page: 326.20 Line No.: 3 Column: l
PacifiCorp imbalance energy service for others.

Schedule Page: 326.20 Line No.: 4 Column: l
Storage and exchange charges.

Schedule Page: 326.20 Line No.: 5 Column: l
Exchange energy expense.

Schedule Page: 326.20 Line No.: 6 Column: l
PacifiCorp imbalance energy service for others.

Schedule Page: 326.20 Line No.: 7 Column: b
Settlement adjustment.

Schedule Page: 326.20 Line No.: 7 Column: l
PacifiCorp imbalance energy service for others.

Schedule Page: 326.20 Line No.: 8 Column: l
PacifiCorp imbalance energy service for others.

Schedule Page: 326.20 Line No.: 9 Column: b
Settlement adjustment.

Schedule Page: 326.20 Line No.: 9 Column: l
PacifiCorp imbalance energy service for others.

Schedule Page: 326.20 Line No.: 11 Column: l
PacifiCorp imbalance energy service for others.
Schedule Page: 326.20 Line No.: 12 Column: a
This footnote applies to all occurrences of "J.P. Morgan Ventures Energy Corp" on pages 326-327. Complete name is J.P. Morgan Ventures Energy Corporation.
Schedule Page: 326.20 Line No.: 12 Column: b
Settlement adjustment.
Schedule Page: 326.20 Line No.: 12 Column: l
PacifiCorp imbalance energy service for others.
Schedule Page: 326.20 Line No.: 13 Column: l
PacifiCorp imbalance energy service for others.
Schedule Page: 326.20 Line No.: 14 Column: l
Station service for third party wind project.
Schedule Page: 326.21 Line No.: 1 Column: b
Settlement adjustment.
Schedule Page: 326.21 Line No.: 1 Column: l
PacifiCorp imbalance energy service for others.
Schedule Page: 326.21 Line No.: 2 Column: l
PacifiCorp imbalance energy service for others.
Schedule Page: 326.21 Line No.: 3 Column: l
Reimbursement for providing station service to third party wind project.
Schedule Page: 326.21 Line No.: 4 Column: l
Reimbursement for providing station service to third party wind project.
Schedule Page: 326.21 Line No.: 5 Column: b
Settlement adjustment.
Schedule Page: 326.21 Line No.: 5 Column: l
PacifiCorp imbalance energy service for others.
Schedule Page: 326.21 Line No.: 6 Column: l
PacifiCorp imbalance energy service for others.
Schedule Page: 326.21 Line No.: 7 Column: b
Settlement adjustment.
Schedule Page: 326.21 Line No.: 7 Column: l
PacifiCorp imbalance energy service for others.
Schedule Page: 326.21 Line No.: 8 Column: l
PacifiCorp imbalance energy service for others.
Schedule Page: 326.21 Line No.: 9 Column: b
Settlement adjustment.
Schedule Page: 326.21 Line No.: 9 Column: l
PacifiCorp imbalance energy service for others.
Schedule Page: 326.21 Line No.: 10 Column: l
PacifiCorp imbalance energy service for others.
Schedule Page: 326.21 Line No.: 11 Column: b
Settlement adjustment.
Schedule Page: 326.21 Line No.: 11 Column: l
Imbalance energy.
Schedule Page: 326.21 Line No.: 12 Column: b
Settlement adjustment.
Schedule Page: 326.21 Line No.: 12 Column: l
PacifiCorp imbalance energy service for others.
Schedule Page: 326.21 Line No.: 13 Column: l
PacifiCorp imbalance energy service for others.
Schedule Page: 326.22 Line No.: 1 Column: b
Settlement adjustment.
Schedule Page: 326.22 Line No.: 1 Column: l

PacifiCorp imbalance energy service for others.

Schedule Page: 326.22 Line No.: 2 Column: l
PacifiCorp imbalance energy service for others.

Schedule Page: 326.22 Line No.: 4 Column: b
Settlement adjustment.

Schedule Page: 326.22 Line No.: 4 Column: l
PacifiCorp imbalance energy service for others.

Schedule Page: 326.22 Line No.: 5 Column: l
PacifiCorp imbalance energy service for others.

Schedule Page: 326.22 Line No.: 7 Column: l
Storage and exchange charges.

Schedule Page: 326.22 Line No.: 9 Column: b
Settlement adjustment.

Schedule Page: 326.22 Line No.: 11 Column: b
Settlement adjustment.

Schedule Page: 326.22 Line No.: 11 Column: l
Exchange energy expense.

Schedule Page: 326.22 Line No.: 12 Column: l
Exchange energy expense.

Schedule Page: 326.22 Line No.: 13 Column: b
Settlement adjustment.

Schedule Page: 326.22 Line No.: 13 Column: l
PacifiCorp imbalance energy service for others.

Schedule Page: 326.22 Line No.: 14 Column: l
PacifiCorp imbalance energy service for others.

Schedule Page: 326.23 Line No.: 1 Column: b
Settlement adjustment.

Schedule Page: 326.23 Line No.: 1 Column: l
PacifiCorp imbalance energy service for others.

Schedule Page: 326.23 Line No.: 2 Column: l
PacifiCorp imbalance energy service for others.

Schedule Page: 326.23 Line No.: 3 Column: a
This footnote applies to all occurrences of "Southern CA Public Power Authority" on pages 326-327. Complete name is Southern California Public Power Authority.

Schedule Page: 326.23 Line No.: 3 Column: l
PacifiCorp imbalance energy service for others.

Schedule Page: 326.23 Line No.: 4 Column: l
PacifiCorp imbalance energy service for others.

Schedule Page: 326.23 Line No.: 5 Column: b
Settlement adjustment.

Schedule Page: 326.23 Line No.: 5 Column: l
PacifiCorp imbalance energy service for others.

Schedule Page: 326.23 Line No.: 6 Column: l
PacifiCorp imbalance energy service for others.

Schedule Page: 326.23 Line No.: 7 Column: b
Settlement adjustment.

Schedule Page: 326.23 Line No.: 7 Column: l
PacifiCorp imbalance energy service for others.

Schedule Page: 326.23 Line No.: 8 Column: l
PacifiCorp imbalance energy service for others.

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: b
Settlement adjustment.
Schedule Page: 326.23 Line No.: 11 Column: l
PacifiCorp imbalance energy service for others.
Schedule Page: 326.23 Line No.: 12 Column: l
PacifiCorp imbalance energy service for others.
Schedule Page: 326.23 Line No.: 13 Column: b
Settlement adjustment.
Schedule Page: 326.23 Line No.: 13 Column: l
Imbalance energy.
Schedule Page: 326.23 Line No.: 14 Column: b
Settlement adjustment.
Schedule Page: 326.23 Line No.: 14 Column: l
PacifiCorp imbalance energy service for others.
Schedule Page: 326.24 Line No.: 1 Column: l
Imbalance energy.
Schedule Page: 326.24 Line No.: 2 Column: l
PacifiCorp imbalance energy service for others.
Schedule Page: 326.24 Line No.: 3 Column: a
This footnote applies to all occurrences of "Utah Associated Municipal Power" on pages 326-327. Complete name is Utah Associated Municipal Power Systems.
Schedule Page: 326.24 Line No.: 3 Column: b
Settlement adjustment.
Schedule Page: 326.24 Line No.: 3 Column: l
PacifiCorp imbalance energy service for others.
Schedule Page: 326.24 Line No.: 4 Column: b
Settlement adjustment.
Schedule Page: 326.24 Line No.: 4 Column: l
Imbalance energy.
Schedule Page: 326.24 Line No.: 5 Column: l
PacifiCorp imbalance energy service for others.
Schedule Page: 326.24 Line No.: 6 Column: l
Imbalance energy.
Schedule Page: 326.24 Line No.: 7 Column: b
Settlement adjustment.
Schedule Page: 326.24 Line No.: 7 Column: l
PacifiCorp imbalance energy service for others.
Schedule Page: 326.24 Line No.: 8 Column: b
Settlement adjustment.
Schedule Page: 326.24 Line No.: 8 Column: l
Imbalance energy.
Schedule Page: 326.24 Line No.: 9 Column: l
PacifiCorp imbalance energy service for others.
Schedule Page: 326.24 Line No.: 10 Column: l
Imbalance energy.
Schedule Page: 326.24 Line No.: 11 Column: l
Imbalance energy.
Schedule Page: 326.24 Line No.: 12 Column: b
Settlement adjustment.
Schedule Page: 326.24 Line No.: 12 Column: l
Imbalance energy.
Schedule Page: 326.24 Line No.: 13 Column: l

Imbalance energy.

Schedule Page: 326.24 Line No.: 14 Column: l

Allocations of energy imbalance market charge codes to transmission customers.

Schedule Page: 326.25 Line No.: 1 Column: b

Not applicable-adjustment for inadvertent interchange.

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Arizona Public Service Company	Arizona Public Service Company		OS
2	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corporation	FNO
3	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corporation	AD
4	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corporation	NF
5	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corporation	SFP
6	Black Hills/Colorado Electric Utility Company			NF
7	Black Hills/Colorado Electric Utility Company			SFP
8	Black Hills Corporation	PacifiCorp	Montana-Dakota Utilities	FNO
9	Black Hills Corporation	PacifiCorp	Montana-Dakota Utilities	AD
10	Black Hills Corporation	PacifiCorp	Black Hills Corporation	LFP
11	Black Hills Corporation	PacifiCorp	Black Hills Corporation	AD
12	Black Hills Corporation			NF
13	Black Hills Corporation			AD
14	Black Hills Corporation			SFP
15	Black Hills Corporation			AD
16	Black Hills Power Marketing			NF
17	Black Hills Power Marketing			AD
18	Black Hills Power Marketing			SFP
19	Black Hills Power Marketing			AD
20	Bonneville Power Administration			OS
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	Bonneville Power Administration	LFP
24	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
25	Bonneville Power Administration	Bonneville Power Administration	Umpqua Indian Utility Cooperative	FNO
26	Bonneville Power Administration	Bonneville Power Administration	Umpqua Indian Utility Cooperative	AD
27	Bonneville Power Administration	Bonneville Power Administration	Benton REA	FNO
28	Bonneville Power Administration	Bonneville Power Administration	Benton REA	AD
29	Bonneville Power Administration	Bonneville Power Administration	Umatilla Electric and Columbia	FNO
30	Bonneville Power Administration	Bonneville Power Administration	Umatilla Electric and Columbia	AD
31	Bonneville Power Administration	U. S. Bureau of Reclamation	Bonneville Power Administration	LFP
32	Bonneville Power Administration	U. S. Bureau of Reclamation	Bonneville Power Administration	AD
33	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS
34	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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)	
R.S. 436		Borah/Brady Sub				1
V11-1,2,3	Yellowtail Sub	Sheridan Substation	1	3,540	3,540	2
V11-1-4,9	Yellowtail Sub	Sheridan Substation	1	453	453	3
V11-1,2,8	Various	Various		2,334	2,334	4
V11-1,2,7	Various	Various		67,599	67,599	5
V11-1,2,8	Various	Various		768	768	6
V11-1,2,7	Various	Various		330	330	7
V11-1,2	Various	Sheridan Substation	46			8
V11-1,2	Various	Sheridan Substation	40			9
V11-1,2,7	Various	Wyodak Substation	52	219,571	219,571	10
V11-1,2,7	Various	Wyodak Substation	52	17,877	17,877	11
V11-1,2,8	Various	Various		18,012	18,012	12
V11-1,2,8	Various	Various		894	894	13
V11-1,2,7	Various	Various		14,023	14,023	14
V11-1,2,7	Various	Various		267	267	15
V11-1,2,8	Various	Various		1,583	1,583	16
V11-1,2,8	Various	Various		48	48	17
V11-1,2,7	Various	Various		471	471	18
V11-1,2,7	Various	Various		49	49	19
R.S. 369	Midpoint Substation	Summer Lake Sub				20
R.S. 237	Various	Various	351	1,103,020	1,103,020	21
R.S. 237	Various	Various	301	89,261	89,261	22
V11-2,7	Lost Creek Hydro Plt	Alvey Substation	58	195,283	195,283	23
V11-2,7	Lost Creek Hydro Plt	Alvey Substation	58	29,721	29,721	24
V11-1-3,5,6	Bonneville Power Adm	Gazley Substation	3	22,533	22,533	25
V11-1-6,9	Bonneville Power Adm	Gazley Substation	3	2,133	2,133	26
V11-1-3,5,6	Bonneville Power Adm	Tieton Substation	1	4,650	4,650	27
V11-1-6,9	Bonneville Power Adm	Tieton Substation	2	788	788	28
V11-1-3,5,6	McNary Substation	Hinkle Substation	1	1,027	1,027	29
V11-1-6,9	McNary Substation	Hinkle Substation	1	133	133	30
V11-2,7	USBR Green Springs	Bonneville Power Adm	19	54,521	54,521	31
V11-2,7	USBR Green Springs	Bonneville Power Adm	19	4,632	4,632	32
R.S. 368	Malin Substation	Malin Substation		668,212	668,212	33
R.S. 368	Malin Substation	Malin Substation		60,304	60,304	34
			4,830	**13,260,949**	**13,147,879**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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.
				1
9,405		14,196	23,601	2
		1,663	1,663	3
	18,996	875	19,871	4
	420,109	19,397	439,506	5
	3,650	165	3,815	6
	1,423	133	1,556	7
1,224,999		55,191	1,280,190	8
		25,614	25,614	9
1,341,098		59,709	1,400,807	10
		56,274	56,274	11
	6,682	296	6,978	12
		499	499	13
	9,992	244	10,236	14
		1,865	1,865	15
	1,564	516	2,080	16
		2,317	2,317	17
	7,865	768	8,633	18
		5,391	5,391	19
				20
4,337,356		67,947	4,405,303	21
		650,754	650,754	22
1,502,041		15,411	1,517,452	23
		57,585	57,585	24
81,559		158,530	240,089	25
		40,453	40,453	26
17,398		5,450	22,848	27
		7,582	7,582	28
5,904		1,461	7,365	29
		1,213	1,213	30
482,800		4,792	487,592	31
		62,110	62,110	32
		246,946	246,946	33
		44,899	44,899	34
50,709,199	**9,461,112**	**32,610,035**	**92,780,346**	

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Bonneville Power Administration	Bonneville Power Administration	Yakama Power	FNO
2	Bonneville Power Administration	Bonneville Power Administration	Yakama Power	AD
3	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS
4	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
5	Bonneville Power Administration			NF
6	Bonneville Power Administration			SFP
7	Bonneville Power Administration	Bonneville Power Administration	Clark Public Utilities	FNO
8	Bonneville Power Administration	Bonneville Power Administration	Clark Public Utilities	AD
9	Cargill Power Markets, LLC			NF
10	Cargill Power Markets, LLC			AD
11	City of Anaheim			NF
12	City of Anaheim			SFP
13	Cowlitz County PUD	Cowlitz County PUD	Bonneville Power Administration	OS
14	Cowlitz County PUD	Cowlitz County PUD	Bonneville Power Administration	AD
15	Deseret Generation & Trans.	Deseret Generation & Trans.	Deseret Generation & Trans.	OS
16	Deseret Generation & Trans.	Deseret Generation & Trans.	Deseret Generation & Trans.	AD
17	Deseret Generation & Trans.			NF
18	Deseret Generation & Trans.			AD
19	Eugene Water & Electric Board			SFP
20	Enel Cove Fort, LLC	Enel Cove Fort, LLC		LFP
21	Exelon Generation Company, LLC.	Bonneville Power Administration	Oregon Direct Access	FNO
22	Exelon Generation Company, LLC.			NF
23	Fall River Rural Electric Cooperative	Marysville Hydro Partners	Idaho Power Company	OS
24	Fall River Rural Electric Cooperative	Marysville Hydro Partners	Idaho Power Company	AD
25	Foote Creek III, LLC	Foote Creek III, LLC	PacifiCorp	OS
26	Foote Creek III, LLC	Foote Creek III, LLC	PacifiCorp	AD
27	Iberdrola Renewables, LLC			NF
28	Iberdrola Renewables, LLC			AD
29	Iberdrola Renewables, LLC			SFP
30	Iberdrola Renewables, LLC			AD
31	Iberdrola Renewables, LLC	Iberdrola Renewables, LLC		OS
32	Iberdrola Renewables, LLC	Iberdrola Renewables, LLC		AD
33	Iberdrola Renewables, LLC	Exxon Mobil	Nevada Power Company	LFP
34	Iberdrola Renewables, LLC	Exxon Mobil	Nevada Power Company	AD
	TOTAL			

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)	
V11-1-3,5,6	Bonneville Power Adm		5	33,133	33,133	1
V11-1-6,9	Bonneville Power Adm		5	3,373	3,373	2
R.S. 299	Various	Various	185	850,964	850,964	3
R.S. 299	Various	Various	193	96,677	96,677	4
V11-1,2,8	Various	Various		1,342	1,342	5
V11-1,2,7	Various	Various				6
V11-1,2,3	Cardwell-Merwin		19	103,419	103,419	7
V11-1-4,9	Cardwell-Merwin		30	13,327	13,327	8
V11-1,2,8	Various	Various		28,739	28,739	9
V11-1,2,8	Various	Various		845	845	10
V11-1,2,8	Various	Various		13,205	13,205	11
V11-1,2,7	Various	Various		738	738	12
R.S. 234	Swift Unit No. 2	Woodland Substation				13
R.S. 234	Swift Unit No. 2	Woodland Substation				14
R.S. 280	Various	Various	98	638,185	638,185	15
R.S. 280	Various	Various	95	46,508	46,508	16
V11-1,2,8	Various	Various		9,328	9,328	17
V11-1,2,8	Various	Various		24	24	18
V11-1,2,7	Various	Various				19
V11-1-3,7	Enel Cove Fort	Red Butte Substation	16			20
V11-1-3,5,6	Bonneville Power Adm	Various	3	8,583	8,583	21
V 11-1-6,8,11	Various	Various		97	97	22
R.S. 322	Targhee Substation	Goshen Substation				23
R.S. 322	Targhee Substation	Goshen Substation				24
S.A. 761	Foote Creek Sub	Various				25
S.A. 761	Foote Creek Sub	Various				26
V11-1-3,8,9	Various	Various		165,283	165,283	27
V11-1-3,8,9	Various	Various		19,167	19,167	28
V11-1-3,7	Various	Various		54,193	54,193	29
V11-1-3,7	Various	Various		4,298	4,298	30
V11-5,6						31
V11-5,6						32
V11-1,2,7	Trona Substation	Red Butte/Mona Sub	31	59,830	59,830	33
V11-1,2,7	Trona Substation	Red Butte/Mona Sub	31	6,935	6,935	34
			4,830	**13,260,949**	**13,147,879**	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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.
138,584		127,560	266,144	1
		44,996	44,996	2
874,891		1,024,573	1,899,464	3
		174,718	174,718	4
	11,888	577	12,465	5
	7		7	6
480,451		138,533	618,984	7
		140,458	140,458	8
	166,189	7,622	173,811	9
		5,497	5,497	10
	101,654	4,310	105,964	11
	5,521	233	5,754	12
		147,267	147,267	13
		13,235	13,235	14
2,663,278		2,150,968	4,814,246	15
		70,491	70,491	16
	78,759	3,602	82,361	17
		173	173	18
	8,427	691,976	700,403	19
148,600		22,020	170,620	20
35,023		13,098	48,121	21
	55,900	63,778	119,678	22
		138,699	138,699	23
		12,609	12,609	24
		52,367	52,367	25
		7,548	7,548	26
	1,480,529	65,969	1,546,498	27
		140,508	140,508	28
	509,765	23,457	533,222	29
		40,538	40,538	30
		217,279	217,279	31
		74,479	74,479	32
804,659		35,825	840,484	33
		33,764	33,764	34
50,709,199	**9,461,112**	**32,610,035**	**92,780,346**	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Iberdrola Renewables, LLC	Bonneville Power Administration	Oregon Direct Access	FNO
2	Iberdrola Renewables, LLC	Iberdrola Renewables, LLC		AD
3	Idaho Power Company	Idaho Power Company	Idaho Power Company	OS
4	Idaho Power Company	Exxon Mobil	Nevada Power Company	LFP
5	Idaho Power Company	Exxon Mobil	Nevada Power Company	AD
6	Idaho Power Company			OS
7	Idaho Power Company			AD
8	Idaho Power Company			OS
9	Idaho Power Company			AD
10	Idaho Power Company			NF
11	Idaho Power Company			SFP
12	Idaho Power Company Marketing			NF
13	JP Morgan Ventures Energy Corp.			NF
14	JP Morgan Ventures Energy Corp.			AD
15	Los Angeles Department of Water & Power			SFP
16	Macquarie Energy, LLC			NF
17	Moon Lake Electric Association	Moon Lake Electric Association	Moon Lake Electric Association	OS
18	Moon Lake Electric Association	Moon Lake Electric Association	Moon Lake Electric Association	AD
19	Morgan Stanley Capital Group, Inc.			NF
20	Morgan Stanley Capital Group, Inc.			AD
21	Morgan Stanley Capital Group, Inc.			SFP
22	Morgan Stanley Capital Group, Inc.			AD
23	Municipal Energy Nebraska, Inc.			NF
24	Nevada Power Company			NF
25	Nevada Power Company			SFP
26	NextEra Energy Resources, LLC	NextEra Energy Resources, LLC	Grant County PUD	LFP
27	NextEra Energy Resources, LLC	NextEra Energy Resources, LLC	Grant County PUD	AD
28	NextEra Energy Resources, LLC			NF
29	NextEra Energy Resources, LLC			AD
30	NextEra Energy Resources, LLC			SFP
31	Noble Americas Energy Solutions LLC	Bonneville Power Administration	Oregon Direct Access	FNO
32	Noble Americas Energy Solutions LLC	Bonneville Power Administration	Oregon Direct Access	AD
33	Pacific Gas & Electric Company			OS
34	Pacific Gas & Electric Company			AD
	TOTAL			

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2015/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.
V11-1-3,5,6	Ponderosa Substation	Various	11	70,895	70,895	1
V11-1-3,5,6	Ponderosa Substation	Various	5	3,806	3,806	2
R.S. 427	Goshen Substation	Goshen Substation				3
V11-1,2,7	Trona Substation	Red Butte/Mona Sub		68,433	68,433	4
V11-1,2,7	Trona Substation	Red Butte/Mona Sub				5
R.S. 257	Antelope Substation	Antelope Substation		145,365	145,365	6
R.S. 257	Antelope Substation	Antelope Substation		20,179	20,179	7
R.S. 203	Jim Bridger Sub	Bridger Pump Sub		33,599	33,599	8
R.S. 203	Jim Bridger Sub	Bridger Pump Sub		3,689	3,689	9
V11-1,2,8	Various	Various		30,652	30,652	10
V11-1,2,7	Various	Various		52,680	52,680	11
V11-1,2,8	Various	Various		490	490	12
V11-5,6,8,11	Various	Various				13
V11-5,6,8,11	Various	Various		176	176	14
V11-1,2,7	Various	Various		2,955	2,955	15
V11-1,2,8	Various	Various		50	50	16
R.S. 302	Duchesne	Duchesne		21,582	21,582	17
R.S. 302	Duchesne	Duchesne		1,994	1,994	18
V11-1-3,8	Various	Various		63,940	63,940	19
V11-1-3,8	Various	Various		2,722	2,722	20
V11-1,2,7	Various	Various		1,381	1,381	21
V11-1,2,7	Various	Various		588	588	22
V11-1,2,8	Various	Various		1	1	23
V11-1,2,8	Various	Various		3,649	3,649	24
V11-1,2,7	Various	Various		700	700	25
V11-1-3,5-7	Wallula Substation	Wala-MIDC path	103	132,898	132,898	26
V11-5-7,9	Wallula Substation	Wala-MIDC path	103	15,845	15,845	27
V11-1-3,8	Various	Various		7,389	7,389	28
V11-1,2,8	Various	Various		222	222	29
V11-1,2,7	Various	Various		15,968	15,968	30
V11-1-3,5,6	Bonneville Power Adm	Various	21	133,859	133,859	31
V11-1-6,9	Bonneville Power Adm	Various	22	12,720	12,720	32
R.S. 607						33
V11-1,2	Various	Various				34
			4,830	**13,260,949**	**13,147,879**	

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.
144,895		68,893	213,788	1
		12,793	12,793	2
				3
928,750		43,142	971,892	4
		-65,539	-65,539	5
		61,520	61,520	6
		6,152	6,152	7
		13,570	13,570	8
		1,357	1,357	9
	204,696	9,379	214,075	10
	125,584	5,772	131,356	11
	3,382	144	3,526	12
	7,228	14,080	21,308	13
		264,264	264,264	14
	41,407	1,744	43,151	15
	252	12	264	16
		17,655	17,655	17
		3,210	3,210	18
	377,317	17,107	394,424	19
		16,554	16,554	20
	10,459	471	10,930	21
		2,748	2,748	22
	57	3	60	23
	8,465	1,878	10,343	24
	19,694	926	20,620	25
1,749,535		351,824	2,101,359	26
		221,758	221,758	27
	169,801	21,627	191,428	28
		6,440	6,440	29
	14,104	655	14,759	30
268,820		137,270	406,090	31
		48,425	48,425	32
		13,291,667	13,291,667	33
		1,208,333	1,208,333	34
50,709,199	**9,461,112**	**32,610,035**	**92,780,346**	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Pacific Gas & Electric Company			OS
2	Pacific Gas & Electric Company			NF
3	Pacific Gas & Electric Company			AD
4	Portland General Electric Company			NF
5	Portland General Electric Company			SFP
6	Portland General Electric Company			OS
7	Powder River Energy Corporation	Western Area Power Administration	Sheridan-Johnson Rural Elect.	OS
8	Powder River Energy Corporation	Western Area Power Administration	Sheridan-Johnson Rural Elect.	AD
9	Powerex Corporation	Bonneville Power Administration	CAISO	LFP
10	Powerex Corporation	Bonneville Power Administration	CAISO	AD
11	Powerex Corporation	Powerex Corporation	CAISO	LFP
12	Powerex Corporation	Powerex Corporation	CAISO	AD
13	Powerex Corporation	Powerex Corporation	CAISO	LFP
14	Powerex Corporation	Powerex Corporation	CAISO	AD
15	Powerex Corporation	Powerex Corporation	CAISO	LFP
16	Powerex Corporation	Powerex Corporation	CAISO	AD
17	Powerex Corporation	Powerex Corporation	CAISO	LFP
18	Powerex Corporation	Powerex Corporation	CAISO	LFP
19	Powerex Corporation	Powerex Corporation	CAISO	LFP
20	Powerex Corporation	Powerex Corporation	CAISO	LFP
21	Powerex Corporation			NF
22	Powerex Corporation			AD
23	Powerex Corporation			SFP
24	Powerex Corporation			AD
25	Public Svc. Co. of CO			AD
26	Puget Sound Power & Light Company			NF
27	Puget Sound Power & Light Company			AD
28	Rainbow Energy Marketing Corporation			NF
29	Rainbow Energy Marketing Corporation			SFP
30	Sacramento Municipal Utility District	Sacramento Municipal Utility Dist	Sacramento Municipal Utility Dist	LFP
31	Sacramento Municipal Utility District	Sacramento Municipal Utility Dist	Sacramento Municipal Utility Dist	AD
32	Salt River Project	Salt River Project	Salt River Project	LFP
33	Salt River Project	Salt River Project	Salt River Project	AD
34	Salt River Project			NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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)	
R.S. 298	Sigurd-Glen Canyon	Pinto-Four Corners				1
V11-1,2,8	Various	Various		1,024	1,024	2
V11-1,2,8	Various	Various		260	260	3
V11-1,2,8	Various	Various		6,594	6,594	4
V11-1,2,7	Various	Various		2,172	2,172	5
R.S. 137	Various	Various				6
R.S. 123	Various	Buffalo Substation				7
R.S. 123	Various	Buffalo Substation				8
V11-1,2,7	Bonneville Power Adm	CRAG View Substation	83	690,921	690,921	9
V11-1,2,7	Bonneville Power Adm	CRAG View Substation	83	46,151	46,151	10
V11-1,7	Malin 500 Substation	Round Mountain Sub	67			11
V11-1,7	Malin 500 Substation	Round Mountain Sub	67			12
V11-1,7	Malin 500 Substation	Round Mountain Sub	67			13
V11-1,7	Malin 500 Substation	Round Mountain Sub	67			14
V11-1,7	Malin 500 Substation	Round Mountain Sub	66			15
V11-1,7	Malin 500 Substation	Round Mountain Sub	66			16
V11-1,7	Malin 500 Substation	Round Mountain Sub	50			17
V11-1,7	Malin 500 Substation	Round Mountain Sub	50			18
V11-1,7	Malin 500 Substation	Round Mountain Sub	150			19
V11-1,7	Malin 500 Substation	Round Mountain Sub	50			20
V11-1-3,8	Various	Various		379,453	379,453	21
V11-1,2,8	Various	Various		4,485	4,485	22
V11-1-3,7	Various	Various		59,045	59,045	23
V11-1,2,7	Various	Various		388	388	24
V11-1,2,7	Various	Various		640	640	25
V11-1,2,8	Various	Various		1	1	26
V11-1,2,8	Various	Various				27
V11-1,2,8	Various	Various		535	535	28
V11-1,2,7	Various	Various				29
V11-1,2,7	Malin Substation	Malin Substation	31	115,619	115,619	30
V11-1,2,7	Malin Substation	Malin Substation	31	12,906	12,906	31
V11-1,2,7	Enel Cove Fort	Red Butte Substation	26	121,653	121,653	32
V11-1,2,7	Enel Cove Fort	Red Butte Substation	26	8,973	8,973	33
V11-1-3,8	Various	Various		22	22	34
			4,830	**13,260,949**	**13,147,879**	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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.
		204,979	204,979	1
	11,114	933	12,047	2
		1,871	1,871	3
	37,344	1,682	39,026	4
	15,138	712	15,850	5
		3,314	3,314	6
		341	341	7
		31	31	8
2,145,757		108,795	2,254,552	9
		90,039	90,039	10
1,723,643		42,962	1,766,605	11
		69,255	69,255	12
1,723,643		42,962	1,766,605	13
		69,255	69,255	14
1,697,917		42,320	1,740,237	15
		68,222	68,222	16
1,286,302		32,062	1,318,364	17
		51,683	51,683	18
3,858,904		96,183	3,955,087	19
		155,049	155,049	20
	2,271,825	118,072	2,389,897	21
		38,666	38,666	22
	140,456	8,937	149,393	23
		2,836	2,836	24
		4,603	4,603	25
	14		14	26
		22	22	27
	1,806	83	1,889	28
	11,136	484	11,620	29
804,659		35,825	840,484	30
		33,764	33,764	31
546,716		25,784	572,500	32
		28,137	28,137	33
	173	7	180	34
50,709,199	**9,461,112**	**32,610,035**	**92,780,346**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	Salt River Project			AD
2	Salt River Project			SFP
3	Sempra Generation			NF
4	Shell Energy Corporation, Inc	NextEra Energy Resources, LLC	Grant County PUD	LFP
5	Shell Energy Corporation, Inc			NF
6	Shell Energy Corporation, Inc			AD
7	Shell Energy Corporation, Inc			SFP
8	Shell Energy Corporation, Inc			AD
9	Sierra Pacific Power Company			OS
10	Sierra Pacific Power Company			AD
11	Southern California Edison Company			OS
12	Southern California Edison Company			NF
13	Southern California Edison Company			AD
14	Southern California Edison Company			SFP
15	Southern California Edison Company			AD
16	Southern California Public Power Authority	Powerex Corporation	Southern California Public Power	OS
17	State of South Dakota	Western Area Power Administration	Black Hills Corporation	LFP
18	State of South Dakota	Western Area Power Administration	Black Hills Corporation	AD
19	Talen Energy Marketing, LLC			NF
20	Talen Energy Marketing, LLC			AD
21	Talen Energy Marketing, LLC			SFP
22	Talen Energy Marketing, LLC			AD
23	Tenaska Power Services Co			NF
24	Tenaska Power Services Co			AD
25	Tenaska Power Services Co			SFP
26	The Energy Authority, Inc.			NF
27	The Energy Authority, Inc.			AD
28	The Energy Authority, Inc.			SFP
29	Thermo No. 1 BE-01, LLC	Thermo Geothermal Project		LFP
30	Thermo No. 1 BE-01, LLC	Thermo Geothermal Project		AD
31	TransAlta Energy Marketing (U.S.) Inc			NF
32	TransAlta Energy Marketing (U.S.) Inc			AD
33	Tri-State Generation & Trans.		Tri-State Generation & Trans.	AD
34	Tri-State Generation & Trans.		Tri-State Generation & Trans.	FNO
	TOTAL			

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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.
V11-1-3,8	Various	Various		846	846	1
V11-1,2,7	Various	Various		24,820	24,820	2
V11-1,2,8	Various	Various				3
V11-1,2,7	Wallula Substation	Wala-MIDC path		63,618	63,618	4
V11-1,2,8	Various	Various		23,329	23,329	5
V11-1,2,8	Various	Various		2,082	2,082	6
V11-1,2,7	Various	Various		13,732	13,732	7
V11-1,2,7	Various	Various		5,286	5,286	8
R.S. 674	Sigurd Substation	Utah-Nevada Border				9
R.S. 674	Sigurd Substation	Utah-Nevada Border				10
R.S. 298	Sigurd-Glen Canyon	Pinto-Four Corners				11
	Various	Various		73,743	73,743	12
	Various	Various		5,321	5,321	13
V11-1-3,7	Various	Various		270	270	14
V11-1-3,7	Various	Various				15
V11-1-3,11	Tieton Substation	Various		62	62	16
V11-1,2,7	Yellowtail Sub	Wyodak Substation	4	16,849	16,849	17
V11-1,2,7	Yellowtail Sub	Wyodak Substation	4	1,518	1,518	18
V11-1,2,8	Various	Various		9,590	9,590	19
V11-1,2,8	Various	Various		465	465	20
V11-1,2,7	Various	Various		3,631	3,631	21
V11-1,2,7	Various	Various		797	797	22
V11-1-3,8	Various	Various		5,680	5,680	23
V11-1-3,8	Various	Various		7,133	7,133	24
V11-1,2,7	Various	Various		1,617	1,617	25
V11-1,2,8	Various	Various		12,387	12,387	26
V11-1,2,8	Various	Various		760	760	27
V11-1,2,7	Various	Various		1,386	1,386	28
V11-1-3,5-7	South Milford Sub	Mona Substation	11	58,503	58,503	29
V11-1-3,5-7,9	South Milford Sub	Mona Substation	11	5,493	5,493	30
V11-1,2,8	Various	Various		42,662	42,662	31
V11-1,2,8	Various	Various		7,564	7,564	32
R.S. 123	Various	Various				33
V11-1,2,3	Dave Johnston Sub	Thermopolis Sub	28	178,814	178,814	34
			4,830	**13,260,949**	**13,147,879**	

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.
		4,322	4,322	1
	123,833	4,071	127,904	2
	7		7	3
				4
	113,731	6,735	120,466	5
		11,554	11,554	6
	7,104	305	7,409	7
		19,823	19,823	8
		68,919	68,919	9
		12,531	12,531	10
		274,174	274,174	11
	2,240,406	458,283	2,698,689	12
		248,346	248,346	13
	2,071	306	2,377	14
		3,496	3,496	15
		3,382	3,382	16
107,277		4,776	112,053	17
		6,596	6,596	18
	60,456	2,829	63,285	19
		3,346	3,346	20
	21,150	982	22,132	21
		5,735	5,735	22
	33,496	1,597	35,093	23
		41,695	41,695	24
	9,327	931	10,258	25
	64,052	2,783	66,835	26
		4,639	4,639	27
	9,147	427	9,574	28
295,052		89,000	384,052	29
		19,505	19,505	30
	222,530	9,818	232,348	31
		43,994	43,994	32
		16,723	16,723	33
729,540		239,802	969,342	34
50,709,199	**9,461,112**	**32,610,035**	**92,780,346**	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Tri-State Generation & Trans.		Tri-State Generation & Trans.	AD
2	Tri-State Generation & Trans.			NF
3	Tri-State Generation & Trans.			AD
4	Tucson Power Company.			NF
5	U.S. Bureau of Reclamation	Bonneville Power Administration	U.S. Bureau of Reclamation	FNO
6	U.S. Bureau of Reclamation	Bonneville Power Administration	U.S. Bureau of Reclamation	AD
7	U.S. Bureau of Reclamation	Western Area Power Administration	Weber Basin Water Conserv.	OS
8	U.S. Bureau of Reclamation	Western Area Power Administration	Weber Basin Water Conserv.	AD
9	U.S. Bureau of Reclamation	Bonneville Power Administration	Crooked River Irrigation District	OS
10	Utah Associated Municipal Power Systems	Utah Associated Municipal Power	Utah Associated Municipal Power	OS
11	Utah Associated Municipal Power Systems	Utah Associated Municipal Power	Utah Associated Municipal Power	AD
12	Utah Associated Municipal Power Systems			NF
13	Utah Associated Municipal Power Systems			AD
14	Utah Associated Municipal Power Systems			SFP
15	Utah Municipal Power Agency	Utah Municipal Power Agency	Utah Municipal Power Agency	OS
16	Utah Municipal Power Agency	Utah Municipal Power Agency	Utah Municipal Power Agency	AD
17	Warm Springs Power Enterprises	Warm Springs Power Enterprises	Portland General Electric Co	OS
18	Warm Springs Power Enterprises	Warm Springs Power Enterprises	Portland General Electric Co	AD
19	Western Area Power Administration	Western Area Power Administration		OS
20	Western Area Power Administration	Western Area Power Administration		AD
21	Western Area Power Administration	Western Area Power Administration		OS
22	Western Area Power Administration	Western Area Power Administration		AD
23	Western Area Power Administration	Western Area Power Administration		OS
24	Western Area Power Administration	Western Area Power Administration	Western Area Power Administration	FNO
25	Western Area Power Administration	Western Area Power Adm. CO River	Western Area Power Administration	AD
26	Western Area Power Adm CO River	Western Area Power Adm. CO River		NF
27	Western Area Power Adm CO River	Western Area Power Adm CO River		SFP
28	Western Area Power Adm CO MO	Western Area Power Adm CO River		NF
29	Western Area Power Adm CO MO	Western Area Power Adm CO River		AD
30	Western Area Power Adm CO MO	Western Area Power Adm CO MO		SFP
31	Western Area Power Adm CO MO	Western Area Power Adm CO MO		AD
32	Accrual			
33				
34				
	TOTAL			

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)	
V11-1-4	Dave Johnston Sub	Thermopolis Sub	32	17,958	17,958	1
V11-1,2,8	Various	Various		709	709	2
V11-1,2,8	Various	Various		36	36	3
V11-1,2,8	Various	Various		800	800	4
V11-1,2,3	Walla Walla Sub	Burbank Pumps	1	2,048	2,048	5
V11-1,2,3	Walla Walla Sub	Burbank Pumps	1	3	3	6
R.S. 286	Various	Various		26,112	26,112	7
R.S. 286	Various	Various		981	981	8
R.S. 67	Redmond Substation	Crooked River Pumps		11,327	11,327	9
R.S. 297	Various	Various	519	2,682,662	2,682,662	10
R.S. 297	Various	Various	409	218,101	218,101	11
V11-1-3,8	Various	Various		4,608	4,608	12
V11-1,2,8	Various	Various		2,522	2,522	13
V11-1-3,7	Various	Various		31,154	31,154	14
R.S. 637	Various	Various	106	611,727	611,727	15
R.S. 637	Various	Various	77	53,740	53,740	16
R.S. 591	Pelton Reregulating	Round Butte Sub		74,331	74,331	17
R.S. 591	Pelton Reregulating	Round Butte Sub		9,001	9,001	18
R.S. 262	Various	Various	330	1,627,305	1,529,667	19
R.S. 262	Various	Various	330	169,693	159,511	20
R.S. 263	Various	Various		73,085	68,268	21
R.S. 263	Various	Various		8,718	8,073	22
R.S. 684	Dave Johnston Sub	Various				23
V11-1,2	Wyoming Distribution	Wyoming Distribution	2	10,506	10,506	24
V11-1,2,8	Various	Wyoming Distribution		2	2	25
V11-1,2,8	Various	Various		1,439	1,439	26
V11-1,2,7	Various	Various				27
V11-1,2,8	Various	Various		498	498	28
V11-1,2,8	Various	Various		188	188	29
V11-1,2,7	Various	Various		190	190	30
V11-1,2,7	Various	Various		425	425	31
				11,623	11,835	32
						33
						34
			4,830	**13,260,949**	**13,147,879**	

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.
		102,672	102,672	1
	4,366	197	4,563	2
		214	214	3
	5,713	265	5,978	4
6,414		10,449	16,863	5
		-3,025	-3,025	6
		26,112	26,112	7
		981	981	8
10,579			10,579	9
13,403,473		2,654,178	16,057,651	10
		592,552	592,552	11
	24,112	3,562	27,674	12
		13,103	13,103	13
	146,544	21,610	168,154	14
2,730,510		504,648	3,235,158	15
		128,183	128,183	16
		109,725	109,725	17
		9,975	9,975	18
2,312,834		550,000	2,862,834	19
		269,047	269,047	20
45,470			45,470	21
		6,170	6,170	22
				23
40,463		46,562	87,025	24
		-2,071	-2,071	25
	8,175	364	8,539	26
	159	7	166	27
	3,583	291	3,874	28
		1,115	1,115	29
	778	44	822	30
		1,746	1,746	31
		1,485,257	1,485,257	32
				33
				34
50,709,199	**9,461,112**	**32,610,035**	**92,780,346**	

Schedule Page: 328 Line No.: 1 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 1 Column: d
Legacy Contract executed between PacifiCorp and Arizona Public Service Company concerning the exchange of transmission services over agreed-upon facilities (Restated Transmission Service Agreement between PacifiCorp and Arizona Public Service Company, Rate Schedule 436). The contract terminates October 31, 2020. See also page 332, Transmission of electricity by others, in this Form No. 1.

Schedule Page: 328 Line No.: 1 Column: f
Glenn Canyon/Four Corners Substation.

Schedule Page: 328 Line No.: 2 Column: d
Network transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 505) terminating no earlier than 12-months from notice by the customer.

Schedule Page: 328 Line No.: 2 Column: m
Distribution voltage service charge. Primary delivery service. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service.

Schedule Page: 328 Line No.: 3 Column: d
Network transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 505) terminating no earlier than 12-months from notice by the customer.

Schedule Page: 328 Line No.: 3 Column: m
2014 transmission and ancillary services.

Schedule Page: 328 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 Line No.: 4 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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.: 5 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 6 Column: a
This footnote applies to all occurrences of "Black Hills/Colorado Electric Utility Company" on pages 328-330. Complete name is Black Hills/Colorado Electric Utility Company, L.P.

Schedule Page: 328 Line No.: 6 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 6 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 6 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 6 Column: m
Transmission resale, purchase of point-to-point transmission. Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 7 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 7 Column: c
Various signatories to the 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.: 7 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 8 Column: d

Network transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 347) terminating on December 31, 2017.

Schedule Page: 328 Line No.: 8 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 9 Column: d

Network transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 347) terminating on December 31, 2017.

Schedule Page: 328 Line No.: 9 Column: m

2014 transmission and ancillary services.

Schedule Page: 328 Line No.: 10 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 67) terminating on December 31, 2023.

Schedule Page: 328 Line No.: 10 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 11 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 67) terminating on December 31, 2023.

Schedule Page: 328 Line No.: 11 Column: m

2014 transmission and ancillary services.

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

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

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

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

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

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 13 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 13 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 13 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 13 Column: m

2014 transmission and ancillary services.

Schedule Page: 328 Line No.: 14 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 14 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 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 Line No.: 14 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

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

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

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

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

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

Transmission resale, amount paid by seller. Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 17 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 17 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 17 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 17 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 18 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 18 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 18 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 18 Column: m

Transmission resale, amount paid by seller. Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 19 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 19 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 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 Line No.: 19 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 20 Column: b

Capacity exchanged and operated by each transmission provider with no receipt or delivery of energy.

Schedule Page: 328 Line No.: 20 Column: c

Capacity exchanged and operated by each transmission provider with no receipt or delivery of energy.

Schedule Page: 328 Line No.: 20 Column: d

Legacy Contract executed between PacifiCorp and Bonneville Power Administration ("BPA") concerning the exchange of transmission services over agreed-upon facilities ("Midpoint-Meridian Transmission Agreement", Rate Schedule 369). This agreement runs concurrently with the AC Intertie Agreement (Rate Schedule 368), which terminates when the facilities subject to that agreement are taken out of service. See also page 332, Transmission of electricity by others, in this Form No. 1.

Schedule Page: 328 Line No.: 21 Column: d

Legacy Contract (3rd Revised Rate Schedule 237) executed between PacifiCorp and BPA for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Contract subject to termination upon the earlier of the termination of the "Exchange Agreement" between PacifiCorp and BPA or the time of the termination of all deliveries as defined in the agreement.

Schedule Page: 328 Line No.: 21 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. 2013-2014 transmission demand adjustments.

Schedule Page: 328 Line No.: 22 Column: d

Legacy Contract (3rd Revised Rate Schedule 237) executed between PacifiCorp and BPA for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Contract subject to termination upon the earlier of the termination of the "Exchange Agreement" between PacifiCorp and BPA or the time of the termination of all deliveries as defined in the agreement.

Schedule Page: 328 Line No.: 22 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. 2014 transmission and ancillary services.

Schedule Page: 328 Line No.: 23 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 656) terminating on August 31, 2030.

Schedule Page: 328 Line No.: 23 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 24 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 656) terminating on August 31, 2030.

Schedule Page: 328 Line No.: 24 Column: m

2014 transmission and ancillary services.

Schedule Page: 328 Line No.: 25 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (8th Revised Service Agreement 229) terminating on September 30, 2028.

Schedule Page: 328 Line No.: 25 Column: f

This footnote applies to all occurrences of "Bonneville Power Adm" on pages 328-330. Complete name is Bonneville Power Administration.

Schedule Page: 328 Line No.: 25 Column: m

Distribution voltage service charge. Primary delivery service. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328 Line No.: 26 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (8th Revised Service Agreement 229) terminating on September 30, 2028.

Schedule Page: 328 Line No.: 26 Column: m

2014 transmission and ancillary services.

Schedule Page: 328 Line No.: 27 Column: c

This footnote applies to all occurrences of "Benton REA" on pages 328-330. Complete name is Benton Rural Electric Association.

Schedule Page: 328 Line No.: 27 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (3rd Revised Service Agreement 539) terminating on September 30, 2028.

Schedule Page: 328 Line No.: 27 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328 Line No.: 28 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (3rd Revised Service Agreement 539) terminating on September 30, 2028.

Schedule Page: 328 Line No.: 28 Column: m

2014 transmission and ancillary services. Operating reserve - supplemental reserve service.

Schedule Page: 328 Line No.: 29 Column: c

This footnote applies to all occurrences of "Umatilla Electric and Columbia" on pages 328-330. Complete name is Umatilla Electric Cooperative Association and Columbia Basin Electric Cooperative, Inc.

Schedule Page: 328 Line No.: 29 Column: d

Network transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 538) terminating on September 30, 2028.

Schedule Page: 328 Line No.: 29 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328 Line No.: 30 Column: d

Network transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 538) terminating on September 30, 2028.

Schedule Page: 328 Line No.: 30 Column: m

2014 transmission and ancillary services.

Schedule Page: 328 Line No.: 31 Column: b

This footnote applies to all occurrences of "U.S. Bureau of Reclamation" on pages 328-330. Complete name is United States Department of Interior Bureau of Reclamation.

Schedule Page: 328 Line No.: 31 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (5th Revised Service Agreement 179) terminating on September 30, 2025.

Schedule Page: 328 Line No.: 31 Column: m

Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 32 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (5th Revised Service Agreement 179) terminating on September 30, 2025.

Schedule Page: 328 Line No.: 32 Column: m

2014 transmission and ancillary services.

Schedule Page: 328 Line No.: 33 Column: d

Legacy Contract (5th Revised Rate Schedule 368) executed between PacifiCorp and BPA for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Subject to termination upon mutual agreement.

Schedule Page: 328 Line No.: 33 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract.

Schedule Page: 328 Line No.: 34 Column: d

Legacy Contract (5th Revised Rate Schedule 368) executed between PacifiCorp and BPA for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Subject to termination upon mutual agreement.

Schedule Page: 328 Line No.: 34 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract. 2014 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 1 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (6th Revised Service Agreement 328) terminating on July 31, 2028.

Schedule Page: 328.1 Line No.: 1 Column: g

White Swan/Toppenish Substations

Schedule Page: 328.1 Line No.: 1 Column: m

Distribution voltage service charge. Primary delivery service. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.1 Line No.: 2 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (6th Revised Service Agreement 328) terminating on July 31, 2028.

Schedule Page: 328.1 Line No.: 2 Column: g

White Swan/Toppenish Substations

Schedule Page: 328.1 Line No.: 2 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 3 Column: d

Legacy Contract (2nd Revised Rate Schedule 299) executed between PacifiCorp and BPA for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Contract terminates with three years notice by BPA or five years notice by PacifiCorp. PacifiCorp provided notice of termination on June 2011.

Schedule Page: 328.1 Line No.: 3 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Charges for scheduling and operating reserves.

Schedule Page: 328.1 Line No.: 4 Column: d

Legacy Contract (2nd Revised Rate Schedule 299) executed between PacifiCorp and BPA for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Contract terminates with three years notice by BPA or five years notice by PacifiCorp. PacifiCorp provided notice of termination on June 2011.

Schedule Page: 328.1 Line No.: 4 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Charges for scheduling and operating reserves. 2014 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 5 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 5 Column: c

Various signatories to the 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.: 5 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 6 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 6 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 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: 328.1 Line No.: 7 Column: d

Network transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 735) terminating on September 30, 2028.

Schedule Page: 328.1 Line No.: 7 Column: g

Chelatchie/View 115kV

Schedule Page: 328.1 Line No.: 7 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.1 Line No.: 8 Column: d

Network transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 735) terminating on September 30, 2028.

Schedule Page: 328.1 Line No.: 8 Column: g

Chelatchie/View 115kV

Schedule Page: 328.1 Line No.: 8 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 9 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 9 Column: c

Various signatories to the 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.: 9 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 10 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 10 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 10 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 10 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 11 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 11 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 11 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 11 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 12 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 12 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 12 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 12 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 13 Column: a

This footnote applies to all occurrences of "Cowlitz County PUD" on pages 328-330. Complete name is Public Utility District No. 1 of Cowlitz County.

Schedule Page: 328.1 Line No.: 13 Column: d

Legacy Contract (Rate Schedule 234) providing for transmission and operation of Swift Hydroelectric plant No. 2 and for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Agreement may be terminated subsequent to the termination of the Power contract as defined in the agreement by the customer providing at least six-months written notice and specifying the date on which the customer will assume responsibility of operations and maintenance of Swift Hydroelectric plant No. 2.

Schedule Page: 328.1 Line No.: 13 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract.

Schedule Page: 328.1 Line No.: 14 Column: d

Legacy Contract (Rate Schedule 234) providing for transmission and operation of Swift Hydroelectric plant No. 2 and for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Agreement may be terminated subsequent to the termination of the Power contract as defined in the agreement by the customer providing at least six months written notice and specifying the date on which the customer will assume responsibility of operations and maintenance of Swift Hydroelectric plant No. 2.

Schedule Page: 328.1 Line No.: 14 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract. 2014 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 15 Column: a

This footnote applies to all occurrences of "Deseret Generation & Trans." on pages 328-330. Complete name is Deseret Generation and Transmission Co-operative.

Schedule Page: 328.1 Line No.: 15 Column: d

Legacy Contract executed between PacifiCorp and Deseret Generation and Transmission Co-operative for transmission service over agreed-upon facilities (6th Amended and Restated Transmission Service and Operating Agreement, Rate Schedule 280). Agreement subject to termination upon mutual agreement.

Schedule Page: 328.1 Line No.: 15 Column: m

Distribution voltage service charge. Meter interrogation services. Penalty revenues covering imbalance charges per Schedules 4 and 9. Scheduling, system control and dispatch service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.1 Line No.: 16 Column: d

Legacy Contract executed between PacifiCorp and Deseret Generation and Transmission Co-operative for transmission service over agreed-upon facilities (6th Amended and Restated Transmission Service and Operating Agreement, Rate Schedule 280). Agreement subject to termination upon mutual agreement.

Schedule Page: 328.1 Line No.: 16 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 17 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 17 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 17 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 17 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 18 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 18 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 18 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 18 Column: m

2014 transmission and ancillary services. Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 19 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 19 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 19 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 19 Column: m

Transmission resale, purchase of point-to-point transmission. Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 20 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 20 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 711) terminating on November 30, 2018.

Schedule Page: 328.1 Line No.: 20 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.1 Line No.: 21 Column: d

Transmission service under the Open Access Transmission Tariff (Service Agreement 789). Service provided pursuant to rules and regulations of Oregon Direct Access. Agreement termination upon notification pursuant to Oregon Direct Access and Open Access Transmission Tariff.

Schedule Page: 328.1 Line No.: 21 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.1 Line No.: 22 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 22 Column: c

Various signatories to the 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

Unauthorized use of transmission service. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.1 Line No.: 23 Column: d

Legacy Contract (Rate Schedule 322) executed between PacifiCorp and Fall River Rural Electric Cooperative for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Terminating on July 31, 2027.

Schedule Page: 328.1 Line No.: 23 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract.

Schedule Page: 328.1 Line No.: 24 Column: d

Legacy Contract (Rate Schedule 322) executed between PacifiCorp and Fall River Rural Electric Cooperative for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Terminating on July 31, 2027.

Schedule Page: 328.1 Line No.: 24 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract. 2014 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 25 Column: d

Service Agreement 761 executed between PacifiCorp and Foote Creek III, LLC (Terra-Gen Operating, LLC) for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Terminating on March 1, 2024.

Schedule Page: 328.1 Line No.: 25 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Distribution voltage service charge.

Schedule Page: 328.1 Line No.: 26 Column: d

Service Agreement 761 executed between PacifiCorp and Foote Creek III, LLC (Terra-Gen Operating, LLC) for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Terminating on March 1, 2024.

Schedule Page: 328.1 Line No.: 26 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. 2014 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 27 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 27 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 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: 328.1 Line No.: 27 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 28 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 28 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 28 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 28 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 29 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 29 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 29 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 29 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 30 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 30 Column: c
Various signatories to the 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.: 30 Column: m
2014 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 31 Column: c
Iberdrola Renewables, LLC and Utah Associated Municipal Power Systems

Schedule Page: 328.1 Line No.: 31 Column: d
Ancillary services under the Open Access Transmission Tariff (1st Revised Service Agreement 476) in effect until superseded.

Schedule Page: 328.1 Line No.: 31 Column: f
Long Hollow, WY Switching Station

Schedule Page: 328.1 Line No.: 31 Column: g
Long Hollow, WY Switching Station

Schedule Page: 328.1 Line No.: 31 Column: m
Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.1 Line No.: 32 Column: c
Iberdrola Renewables, LLC and Utah Associated Municipal Power Systems

Schedule Page: 328.1 Line No.: 32 Column: d
Ancillary services under the Open Access Transmission Tariff (1st Revised Service Agreement 476) in effect until superseded.

Schedule Page: 328.1 Line No.: 32 Column: f
Long Hollow, WY Switching Station

Schedule Page: 328.1 Line No.: 32 Column: g
Long Hollow, WY Switching Station

Schedule Page: 328.1 Line No.: 32 Column: m
2014 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 33 Column: c
This footnote applies to all occurrences of "Nevada Power Company" on pages 328-330. Nevada Power Company is a principal subsidiary of NV Energy, Inc., which is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company, PacifiCorp's indirect parent company.

Schedule Page: 328.1 Line No.: 33 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (8th Revised Service Agreement 279) terminating on April 30, 2019.

Schedule Page: 328.1 Line No.: 33 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 34 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (8th Revised Service Agreement 279) terminating on April 30, 2019.

Schedule Page: 328.1 Line No.: 34 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 1 Column: d

Network transmission service under the Open Access Transmission Tariff (Service Agreement 742) terminating on April 30, 2018.

Schedule Page: 328.2 Line No.: 1 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.2 Line No.: 2 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 2 Column: d

Network transmission service under the Open Access Transmission Tariff (Service Agreement 742) terminating on April 30, 2018.

Schedule Page: 328.2 Line No.: 2 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 3 Column: d

Legacy Contract (Rate Schedule 427) executed between PacifiCorp and Idaho Power Company concerning the exchange of transmission services over agreed-upon facilities (Draft Transmission Services Agreement between PacifiCorp and Idaho Power Company, Draft 1 – 5/19/95 (“Goshen Agreement”)). Termination of this agreement occurs at the end of the calendar month following the earlier of the effectiveness of a replacement contract or upon three years written notice of termination as long as PacifiCorp has facilities in place to serve PacifiCorp's Big Grassy load. See also page 332, Transmission of electricity by others, in this Form No. 1.

Schedule Page: 328.2 Line No.: 4 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (8th Revised Service Agreement 212) terminating on May 31, 2019.

Schedule Page: 328.2 Line No.: 4 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 5 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (8th Revised Service Agreement 212) terminating on May 31, 2019.

Schedule Page: 328.2 Line No.: 5 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 6 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 6 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 6 Column: d

Legacy Contract (Rate Schedule 257) executed between PacifiCorp and Idaho Power Company for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge for the Antelope Substation terminating coterminous with the Idaho/United States Department of Education Supply Agreement.

Schedule Page: 328.2 Line No.: 6 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge.

Schedule Page: 328.2 Line No.: 7 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 7 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 7 Column: d

Legacy Contract (Rate Schedule 257) executed between PacifiCorp and Idaho Power Company for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge for the Antelope Substation terminating coterminous with the

Idaho/United States Department of Education Supply Agreement.

Schedule Page: 328.2 Line No.: 7 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. 2014 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 8 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 8 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 8 Column: d

Legacy Contract (Rate Schedule 203) executed between PacifiCorp and Idaho Power Company for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge (Service Agreement 203) for the Bridger Pump Substation. Agreement terminates upon 12-months written notice.

Schedule Page: 328.2 Line No.: 8 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge.

Schedule Page: 328.2 Line No.: 9 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 9 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 9 Column: d

Legacy Contract (Rate Schedule 203) executed between PacifiCorp and Idaho Power Company for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge (Service Agreement 203) for the Bridger Pump Substation. Agreement terminates upon 12-months written notice.

Schedule Page: 328.2 Line No.: 9 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. 2014 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 10 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 10 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 11 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 11 Column: c

Various signatories to the 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.: 11 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 12 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 12 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 12 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 12 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 13 Column: a
This footnote applies to all occurrences of "JP Morgan Ventures Energy Corp." on pages 328-330. Complete name is JP Morgan Ventures Energy Corporation.

Schedule Page: 328.2 Line No.: 13 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 13 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 13 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 13 Column: m
Unauthorized use of transmission service. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.2 Line No.: 14 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 14 Column: c
Various signatories to the 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.: 14 Column: m
2014 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 15 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 15 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 15 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 15 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 16 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 16 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 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: 328.2 Line No.: 16 Column: m
Transmission resale, amount paid by seller. Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 17 Column: d
Legacy Contract (3rd Revised Rate Schedule 302) executed between PacifiCorp and Moon Lake Electric Association for transmission and interconnection service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Either party may terminate the agreement at any time after October 14, 2016, by providing two years written notice.

Schedule Page: 328.2 Line No.: 17 Column: m
Charge for transmission service over agreed-upon facilities and/or subject to a sole-use

or facilities charge based on a capacity factor and/or proportional use as defined in the contract.

Schedule Page: 328.2 Line No.: 18 Column: d

Legacy Contract (3rd Revised Rate Schedule 302) executed between PacifiCorp and Moon Lake Electric Association for transmission and interconnection service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Either party may terminate the agreement at any time after October 14, 2016, by providing two years written notice.

Schedule Page: 328.2 Line No.: 18 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract. 2014 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 19 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 19 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 19 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 19 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.2 Line No.: 20 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 20 Column: c

Various signatories to the 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.: 20 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 21 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 21 Column: c

Various signatories to the 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

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.2 Line No.: 22 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 22 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 22 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 22 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 23 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 23 Column: c

Various signatories to the 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
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 24 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 24 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 24 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 24 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 25 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 25 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 25 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 25 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 26 Column: c
This footnote applies to all occurrences of "Grant County PUD" on pages 328-330. Complete name is Grant County Public Utility District.

Schedule Page: 328.2 Line No.: 26 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 733) terminating on November 30, 2017.

Schedule Page: 328.2 Line No.: 26 Column: m
Transmission resale, purchase of point-to-point transmission. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.2 Line No.: 27 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 733) terminating on November 30, 2017.

Schedule Page: 328.2 Line No.: 27 Column: m
2014 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 28 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 28 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 28 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 28 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.2 Line No.: 29 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 29 Column: c

Various signatories to the 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.: 29 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 30 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 30 Column: c

Various signatories to the 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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 31 Column: d

Transmission service under the Open Access Transmission Tariff (6th Revised Service Agreement 299). Service provided pursuant to rules and regulations of Oregon Direct Access. Agreement termination upon notification pursuant to Oregon Direct Access and Open Access Transmission Tariff.

Schedule Page: 328.2 Line No.: 31 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.2 Line No.: 32 Column: d

Transmission service under the Open Access Transmission Tariff (6th Revised Service Agreement 299). Service provided pursuant to rules and regulations of Oregon Direct Access. Agreement termination upon notification pursuant to Oregon Direct Access and Open Access Transmission Tariff.

Schedule Page: 328.2 Line No.: 32 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 33 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 33 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 33 Column: d

Legacy Contract (Rate Schedule 607) executed between PacifiCorp and Pacific Gas & Electric Company for transmission service over agreed-upon facilities (Malin to Round Mountain) and/or subject to a sole-use or facilities charge. Terminating December 31, 2017. See PacifiCorp, Docket No. ER07-882, et al, Settlement Agreement, Appendix 2 (filed November 20, 2007).

Schedule Page: 328.2 Line No.: 33 Column: f

Malin to Indian Springs line segment

Schedule Page: 328.2 Line No.: 33 Column: g

Malin to Indian Springs line segment

Schedule Page: 328.2 Line No.: 33 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract.

Schedule Page: 328.2 Line No.: 34 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 34 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 34 Column: d

Legacy Contract (Rate Schedule 607) executed between PacifiCorp and Pacific Gas & Electric Company for transmission service over agreed-upon facilities (Malin to Round Mountain) and/or subject to a sole-use or facilities charge. Terminating December 31, 2017. See PacifiCorp, Docket No. ER07-882, et al, Settlement Agreement, Appendix 2 (filed November 20, 2007).

Schedule Page: 328.2 Line No.: 34 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract. 2014 transmission and ancillary services.

Schedule Page: 328.3 Line No.: 1 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 1 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 1 Column: d

Legacy Contract (Rate Schedule 298) executed between PacifiCorp and Pacific Gas & Electric Company for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge (phase shifting transformers at Sigurd-Glen Canyon 230kV transmission line and Pinto-Four Corners 345kV transmission line. Terminating February 12, 2020.

Schedule Page: 328.3 Line No.: 1 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge.

Schedule Page: 328.3 Line No.: 2 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 2 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 2 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 3 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 3 Column: c

Various signatories to the 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.: 3 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 4 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 4 Column: c

Various signatories to the 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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 5 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 5 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 5 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 6 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 6 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 6 Column: d

Legacy Contract (1st Revised Rate Schedule 137) executed between PacifiCorp and Portland General Electric Company for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge for the Dalreed Substation, which terminated December 2013.

Schedule Page: 328.3 Line No.: 6 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge.

Schedule Page: 328.3 Line No.: 7 Column: c

This footnote applies to all occurrences of "Sheridan-Johnson Rural Elect." on pages 328-330. Complete name is Sheridan-Johnson Rural Electric Association.

Schedule Page: 328.3 Line No.: 7 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 Rural Electric Association's load at PacifiCorp's Buffalo Substation in Wyoming.

Schedule Page: 328.3 Line No.: 7 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge.

Schedule Page: 328.3 Line No.: 8 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 Rural Electric Association's load at PacifiCorp's Buffalo Substation in Wyoming.

Schedule Page: 328.3 Line No.: 8 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. 2014 transmission and ancillary services.

Schedule Page: 328.3 Line No.: 9 Column: c

This footnote applies to all occurrences of "CAISO" on pages 328-330. Complete name is California Independent System Operator Corporation.

Schedule Page: 328.3 Line No.: 9 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (8th Revised Service Agreement 169) terminating on October 31, 2020.

Schedule Page: 328.3 Line No.: 9 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 10 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (8th Revised Service Agreement 169) terminating on October 31, 2020.

Schedule Page: 328.3 Line No.: 10 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.3 Line No.: 11 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (2nd Revised

Service Agreement 700) terminating on March 31, 2017.

Schedule Page: 328.3 Line No.: 11 Column: m

Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 12 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 700) terminating on March 31, 2017.

Schedule Page: 328.3 Line No.: 12 Column: m

2014 transmission and ancillary services. Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 13 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 701) terminating on March 31, 2017.

Schedule Page: 328.3 Line No.: 13 Column: m

Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 14 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 701) terminating on March 31, 2017.

Schedule Page: 328.3 Line No.: 14 Column: m

2014 transmission and ancillary services. Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 15 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 702) terminating on March 31, 2017.

Schedule Page: 328.3 Line No.: 15 Column: m

Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 16 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 702) terminating on March 31, 2017.

Schedule Page: 328.3 Line No.: 16 Column: m

2014 transmission and ancillary services. Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 17 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 748) terminating on December 31, 2018.

Schedule Page: 328.3 Line No.: 17 Column: m

Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 18 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 748) terminating on December 31, 2018.

Schedule Page: 328.3 Line No.: 18 Column: m

Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 19 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 749) terminating on December 31, 2018.

Schedule Page: 328.3 Line No.: 19 Column: m

Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 20 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 749) terminating on December 31, 2018.

Schedule Page: 328.3 Line No.: 20 Column: m

Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 21 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 21 Column: c

Various signatories to the 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

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.3 Line No.: 22 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 22 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 22 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.3 Line No.: 23 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 23 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 23 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.3 Line No.: 24 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 24 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 24 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 24 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.3 Line No.: 25 Column: a

This footnote applies to all occurrences of "Public Svc. Co. of CO" on pages 328-330. Complete name is Public Service Company of Colorado.

Schedule Page: 328.3 Line No.: 25 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 25 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 25 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 25 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.3 Line No.: 26 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 26 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 27 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 27 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 27 Column: m
2014 transmission and ancillary services.

Schedule Page: 328.3 Line No.: 28 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 28 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 28 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 29 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 29 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 29 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 30 Column: b
This footnote applies to all occurrences of "Sacramento Municipal Utility Dist" on pages 328-330. Complete name is Sacramento Municipal Utility District.

Schedule Page: 328.3 Line No.: 30 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 795) terminating on December 31, 2020.

Schedule Page: 328.3 Line No.: 30 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 31 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 795) terminating on December 31, 2020.

Schedule Page: 328.3 Line No.: 31 Column: m
2014 transmission and ancillary services.

Schedule Page: 328.3 Line No.: 32 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 809) terminating on October 31, 2020.

Schedule Page: 328.3 Line No.: 32 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.3 Line No.: 33 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 809) terminating on October 31, 2020.

Schedule Page: 328.3 Line No.: 33 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.3 Line No.: 34 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 34 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 34 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 34 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 1 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 1 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

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.: 1 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.4 Line No.: 2 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 2 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

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.: 2 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 3 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 3 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

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.: 4 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (9th Revised Service Agreement 791) terminating upon written notification.

Schedule Page: 328.4 Line No.: 5 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 5 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 5 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.4 Line No.: 6 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 6 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 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: 328.4 Line No.: 6 Column: m
2014 transmission and ancillary services.
Schedule Page: 328.4 Line No.: 7 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 Line No.: 7 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 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: 328.4 Line No.: 7 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.
Schedule Page: 328.4 Line No.: 8 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 Line No.: 8 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 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: 328.4 Line No.: 8 Column: m
2014 transmission and ancillary services.
Schedule Page: 328.4 Line No.: 9 Column: a
Sierra Pacific Power Company is a principal subsidiary of NV Energy, Inc., which is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company, PacifiCorp's indirect parent company.
Schedule Page: 328.4 Line No.: 9 Column: b
Operation, maintenance or facility lease services with no receipt or delivery of energy.
Schedule Page: 328.4 Line No.: 9 Column: c
Operation, maintenance or facility lease services with no receipt or delivery of energy.
Schedule Page: 328.4 Line No.: 9 Column: d
Legacy Contract (Rate Schedule 674) executed between PacifiCorp and Sierra Pacific Power Company for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Terminating in September 2022.
Schedule Page: 328.4 Line No.: 9 Column: m
Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge.
Schedule Page: 328.4 Line No.: 10 Column: b
Operation, maintenance or facility lease services with no receipt or delivery of energy.
Schedule Page: 328.4 Line No.: 10 Column: c
Operation, maintenance or facility lease services with no receipt or delivery of energy.
Schedule Page: 328.4 Line No.: 10 Column: d
Legacy Contract (Rate Schedule 674) executed between PacifiCorp and Sierra Pacific Power Company for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Terminating in September 2022.
Schedule Page: 328.4 Line No.: 10 Column: m
Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. 2014 transmission and ancillary services.
Schedule Page: 328.4 Line No.: 11 Column: b
Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 11 Column: c
Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 11 Column: d
Use of Facilities Agreement - Phase shifting transformers at Sigurd-Glen Canyon 230kV transmission line and Pinto-Four Corners 345kV transmission line (Rate Schedule 298), terminating February 12, 2020.

Schedule Page: 328.4 Line No.: 11 Column: m
Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge.

Schedule Page: 328.4 Line No.: 12 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 12 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 12 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.4 Line No.: 12 Column: e
V11-1-3,5,6,8,11

Schedule Page: 328.4 Line No.: 12 Column: m
Unauthorized use of transmission service. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.4 Line No.: 13 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 13 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 13 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.4 Line No.: 13 Column: e
V11-1-3,5,6,8,11

Schedule Page: 328.4 Line No.: 13 Column: m
2014 transmission and ancillary services.

Schedule Page: 328.4 Line No.: 14 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 14 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 14 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.4 Line No.: 15 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 15 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 15 Column: m
2014 transmission and ancillary services.

Schedule Page: 328.4 Line No.: 16 Column: c

Complete name is Southern California Public Power Authority.

Schedule Page: 328.4 Line No.: 16 Column: d

Small Generator Interconnection Agreement (Service Agreement 629) executed between PacifiCorp and Southern California Public Power Authority terminating on November 30, 2019 or such other longer period as the Interconnection Customer may request and shall be automatically renewed for each successive one-year period thereafter, unless terminated earlier based on terms listed in the contract.

Schedule Page: 328.4 Line No.: 16 Column: m

Unauthorized use of transmission service. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.4 Line No.: 17 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 779) terminating on August 31, 2019.

Schedule Page: 328.4 Line No.: 17 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.4 Line No.: 18 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 779) terminating on August 31, 2019.

Schedule Page: 328.4 Line No.: 18 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.4 Line No.: 19 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 19 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 19 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 20 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 20 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 20 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.4 Line No.: 21 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 21 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 21 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 22 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 22 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 22 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 23 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 23 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 23 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.4 Line No.: 24 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 24 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 24 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.4 Line No.: 24 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.4 Line No.: 25 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 25 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 25 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.4 Line No.: 25 Column: m

Transmission resale, amount paid by seller. Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 26 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 26 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 26 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 27 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 27 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 27 Column: m
2014 transmission and ancillary services.
Schedule Page: 328.4 Line No.: 28 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 Line No.: 28 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 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: 328.4 Line No.: 28 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.
Schedule Page: 328.4 Line No.: 29 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 Line No.: 29 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 568) terminating on April 30, 2029.
Schedule Page: 328.4 Line No.: 29 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.
Schedule Page: 328.4 Line No.: 30 Column: c
Various signatories to the Volume 11 Point-to-Point Transmissions Tariff.
Schedule Page: 328.4 Line No.: 30 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 568) terminating on April 30, 2029.
Schedule Page: 328.4 Line No.: 30 Column: m
2014 transmission and ancillary services.
Schedule Page: 328.4 Line No.: 31 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 Line No.: 31 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 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: 328.4 Line No.: 31 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.
Schedule Page: 328.4 Line No.: 32 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 Line No.: 32 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 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: 328.4 Line No.: 32 Column: m
2014 transmission and ancillary services.
Schedule Page: 328.4 Line No.: 33 Column: a
This footnote applies to all occurrences of "Tri-State Generation & Trans." on pages 328-330. Complete name is Tri-State Generation and Transmission Association, Inc.
Schedule Page: 328.4 Line No.: 33 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 Line No.: 33 Column: d

Legacy Contract (2nd Revised Rate Schedule 123) executed between PacifiCorp and Tri-State Generation and Transmission Association, Inc. for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Terminating on October 1, 2014.

Schedule Page: 328.4 Line No.: 33 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.4 Line No.: 34 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 34 Column: d

Network transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 628) terminating on June 30, 2021.

Schedule Page: 328.4 Line No.: 34 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service.

Schedule Page: 328.5 Line No.: 1 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 1 Column: d

Network transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 628) terminating on June 30, 2021.

Schedule Page: 328.5 Line No.: 1 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.5 Line No.: 2 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 2 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 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: 328.5 Line No.: 2 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 3 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 3 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 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: 328.5 Line No.: 3 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.5 Line No.: 4 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 4 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 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: 328.5 Line No.: 4 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 5 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (Service Agreement 506) terminating upon written notification.

Schedule Page: 328.5 Line No.: 5 Column: m

Distribution voltage service charge. Primary delivery service. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.5 Line No.: 6 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (Service Agreement 506) terminating upon written notification.

Schedule Page: 328.5 Line No.: 6 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.5 Line No.: 7 Column: c

This footnote applies to all occurrences of "Weber Basin Water Conserv." on pages 328-330. Complete name is Weber Basin Water Conservancy District.

Schedule Page: 328.5 Line No.: 7 Column: d

Legacy Contract (3rd Revised Rate Schedule 286) executed between PacifiCorp and United States Department of the Interior, Bureau of Reclamation Weber Basin Water Conservancy District for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge for energy deliveries at and below 138kV. Agreement termination any time after April 1, 2040 with four years written notification.

Schedule Page: 328.5 Line No.: 7 Column: m

Energy consumption charge for deliveries at and below 138kV.

Schedule Page: 328.5 Line No.: 8 Column: d

Legacy Contract (3rd Revised Rate Schedule 286) executed between PacifiCorp and United States Department of the Interior, Bureau of Reclamation Weber Basin Water Conservancy District for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge for energy deliveries at and below 138kV. Agreement termination any time after April 1, 2040 with four years written notification.

Schedule Page: 328.5 Line No.: 8 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.5 Line No.: 9 Column: d

Legacy Contract (3rd Amended Rate Schedule 67) executed between PacifiCorp and United States Department of the Interior, Bureau of Reclamation Crooked River Irrigation District for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Agreement termination with one year written notice.

Schedule Page: 328.5 Line No.: 10 Column: b

This footnote applies to all occurrences of "Utah Associated Municipal Power" on pages 328-330. Complete name is Utah Associated Municipal Power Systems.

Schedule Page: 328.5 Line No.: 10 Column: d

Legacy Contract executed between PacifiCorp and Utah Associated Municipal Power Systems for transmission service over agreed-upon facilities (3rd Amended and Restated Transmission Service and Operating Agreement, 3rd Revised Rate Schedule 297). Agreement subject to termination upon mutual agreement and replacement agreements are in effect.

Schedule Page: 328.5 Line No.: 10 Column: m

Distribution voltage service charge. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.5 Line No.: 11 Column: d

Legacy Contract executed between PacifiCorp and Utah Associated Municipal Power Systems for transmission service over agreed-upon facilities (3rd Amended and Restated Transmission Service and Operating Agreement, 3rd Revised Rate Schedule 297). Agreement subject to termination upon mutual agreement and replacement agreements are in effect.

Schedule Page: 328.5 Line No.: 11 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.5 Line No.: 12 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 12 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 12 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.5 Line No.: 12 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.5 Line No.: 13 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 13 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 13 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.5 Line No.: 13 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.5 Line No.: 14 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 14 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 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: 328.5 Line No.: 14 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.5 Line No.: 15 Column: d

Legacy Contract (5th Revised Rate Schedule 637) executed between PacifiCorp and Utah Municipal Power Agency for transmission service over agreed-upon facilities (Amended and Restated Transmission Service and Operating Agreement). Subject to termination upon mutual agreement and replacement agreements are in effect.

Schedule Page: 328.5 Line No.: 15 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.5 Line No.: 16 Column: d

Legacy Contract (5th Revised Rate Schedule 637) executed between PacifiCorp and Utah Municipal Power Agency for transmission service over agreed-upon facilities (Amended and Restated Transmission Service and Operating Agreement). Subject to termination upon mutual agreement and replacement agreements are in effect.

Schedule Page: 328.5 Line No.: 16 Column: m

2014 transmission and ancillary services.

Schedule Page: 328.5 Line No.: 17 Column: c

This footnote applies to all occurrences of "Portland General Electric Co" on pages 328-330. Complete name is Portland General Electric Company.

Schedule Page: 328.5 Line No.: 17 Column: d

Legacy Contract (Rate Schedule 591) executed between PacifiCorp and Warm Springs Power Enterprises for transmission service over agreed-upon facilities and/or subject to sole-use or facilities charge. Terminating on January 31, 2032.

Schedule Page: 328.5 Line No.: 17 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract.

Schedule Page: 328.5 Line No.: 18 Column: d

Legacy Contract (Rate Schedule 591) executed between PacifiCorp and Warm Springs Power Enterprises for transmission service over agreed-upon facilities and/or subject to sole-use or facilities charge. Terminating on January 31, 2032.

Schedule Page: 328.5 Line No.: 18 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract. 2014 transmission and ancillary services.

Schedule Page: 328.5 Line No.: 19 Column: c

Various Western Area Power Administration customers in PacifiCorp's control area.

Schedule Page: 328.5 Line No.: 19 Column: d

Legacy Contract (Rate Schedule 262) executed between PacifiCorp and Western Area Power Administration for transmission and interconnection service over agreed-upon facilities and/or subject to a sole-use or facilities charge for load service to preferential customers for deliveries of Colorado River Storage Project power and energy. Agreement termination upon three years after written notice and mutual consent.

Schedule Page: 328.5 Line No.: 19 Column: m

Fixed termination fee associated with a contract cancellation applied for the duration of this agreement.

Schedule Page: 328.5 Line No.: 20 Column: c

Various Western Area Power Administration customers in PacifiCorp's control area.

Schedule Page: 328.5 Line No.: 20 Column: d

Legacy Contract (Rate Schedule 262) executed between PacifiCorp and Western Area Power Administration for transmission and interconnection service over agreed-upon facilities and/or subject to a sole-use or facilities charge for load service to preferential customers for deliveries of Colorado River Storage Project power and energy. Agreement termination upon three years after written notice and mutual consent.

Schedule Page: 328.5 Line No.: 20 Column: m

Fixed termination fee associated with a contract cancellation applied for the duration of this agreement. 2014 transmission and ancillary services.

Schedule Page: 328.5 Line No.: 21 Column: c

Various Western Area Power Administration customers in PacifiCorp's control area.

Schedule Page: 328.5 Line No.: 21 Column: d

Legacy Contract (Rate Schedule 263) executed between PacifiCorp and Western Area Power Administration for transmission and interconnection service over agreed-upon facilities and/or subject to a sole-use or facilities charge for load service to low voltage customers for deliveries of power and energy from Salt Lake City Area Integrated Projects, including the Colorado River Storage Projects, to certain municipalities at service below 138kV. Agreement termination upon three years after written notice and mutual consent.

Schedule Page: 328.5 Line No.: 22 Column: c

Various Western Area Power Administration customers in PacifiCorp's control area.

Schedule Page: 328.5 Line No.: 22 Column: d

Legacy Contract (Rate Schedule 263) executed between PacifiCorp and Western Area Power Administration for transmission and interconnection service over agreed-upon facilities and/or subject to a sole-use or facilities charge for load service to low voltage customers for deliveries of power and energy from Salt Lake City Area Integrated Projects, including the Colorado River Storage Projects, to certain municipalities at service below 138kV. Agreement termination upon three years after written notice and mutual consent.

Schedule Page: 328.5 Line No.: 22 Column: m

Charges for low-voltage transmission of power and energy. 2014 transmission and ancillary services.

Schedule Page: 328.5 Line No.: 23 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 23 Column: d

Legacy Contract (Rate Schedule 684) executed between PacifiCorp and Western Area Power Administration concerning the exchange of transmission services over agreed-upon facilities. The contract terminates 50 years from execution. See also page 332, Transmission of electricity by others, in this Form No. 1.

Schedule Page: 328.5 Line No.: 24 Column: d

Evergreen network transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 175).

Schedule Page: 328.5 Line No.: 24 Column: m

Distribution voltage service charge. Primary delivery service. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.5 Line No.: 25 Column: b

This footnote applies to all occurrences of "Western Area Power Adm. CO River" on pages 328-330. Complete name is Western Area Power Administration Colorado River Storage Project.

Schedule Page: 328.5 Line No.: 25 Column: d

Evergreen network transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 175).

Schedule Page: 328.5 Line No.: 25 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. 2014 transmission and ancillary services.

Schedule Page: 328.5 Line No.: 26 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 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: 328.5 Line No.: 26 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 27 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 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: 328.5 Line No.: 27 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 28 Column: a

This footnote applies to all occurrences of "Western Area Power Adm. CO MO" on pages 328-330. Complete name is Western Area Power Administration Colorado Missouri.

Schedule Page: 328.5 Line No.: 28 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 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: 328.5 Line No.: 28 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 29 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 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: 328.5 Line No.: 29 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 30 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 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: 328.5 Line No.: 30 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 31 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 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: 328.5 Line No.: 31 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 32 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, Revenues from transmission of electricity for others, during the period.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	Arizona Public Service	AD				233		233
2	Arizona Public Service	LFP	509,724	509,724	1,706,862			1,706,862
3	Arizona Public Service	NF	46,460	46,460	291,641			291,641
4	Arizona Public Service	OS					16,579	16,579
5	Arizona Public Service	OS						
6	Arizona Public Service	SFP	79,131	79,131	501,421			501,421
7	Ashland, City of	FNS	2,168	2,168		20,835		20,835
8	Avista Corporation	FNS	53,171	55,224	245,458			245,458
9	Avista Corporation	NF	8,061	8,061	46,512			46,512
10	Avista Corporation	FNS	42,640	42,640	163,833			163,833
11	Basin Elect. Power Coop	NF	2,812	2,812		4,190		4,190
12	Big Horn Rural Electric	OLF					175,561	175,561
13	Black Hills Power, Inc.	AD	7	7	45		8	53
14	Black Hills Power, Inc.	NF	19,361	19,361	19,208			19,208
15	Black Hills Power, Inc.	OS					28,028	28,028
16	Black Hills Power, Inc.	SFP	7,832	7,832	42,280			42,280
	TOTAL		15,461,404	15,914,125	122,878,918	5,161,909	20,384,518	148,425,345

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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)	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	Bonneville Power Admin	AD			-169,737		27,044	-142,693
2	Bonneville Power Admin	FNS			6,977,680			6,977,680
3	Bonneville Power Admin	LFP	4,421,278	4,421,278	65,636,117			65,636,117
4	Bonneville Power Admin	NF	48,909	48,909		245,170		245,170
5	Bonneville Power Admin	OLF	4,328,027	4,580,617	23,912,278		100,881	24,013,159
6	Bonneville Power Admin	OS	29,384	29,384			756,789	756,789
7	Bonneville Power Admin	OS						
8	Bonneville Power Admin	SFP	921,798	921,798		4,639,929		4,639,929
9	CA Ind. Sys. Operator	AD					-1,242	-1,242
10	CA Ind. Sys. Operator	OS					628,787	628,787
11	CA Ind. Sys. Operator	SFP	18,375	18,375		180,843		180,843
12	Deseret Gen & Trans	LFP	135,730	135,730	4,693,644			4,693,644
13	Deseret Gen & Trans	NF	5,779	5,779	55,824			55,824
14	El Paso Electric Co.	NF	6,118	6,118	4,286			4,286
15	El Paso Electric Co.	OS					3,408	3,408
16	El Paso Electric Co.	SFP	23,387	23,387	17,291			17,291
	TOTAL		15,461,404	15,914,125	122,878,918	5,161,909	20,384,518	148,425,345

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	Flathead Elect Coop Inc	OS					68,820	68,820
2	Hermiston Gen Co L.P.	OS					194,174	194,174
3	Idaho Power Company	AD			228,956			228,956
4	Idaho Power Company	FNS			9,571			9,571
5	Idaho Power Company	LFP	2,077,819	2,210,950	5,753,990			5,753,990
6	Idaho Power Company	NF	688,028	742,597	2,148,304			2,148,304
7	Idaho Power Company	OS				30,821	11,134,008	11,164,829
8	Idaho Power Company	OS						
9	Idaho Power Company	SFP	172,152	172,152	440,732			440,732
10	Moon Lake Elect. Assoc.	FNS					292,085	292,085
11	Morgan City Corporation	LFP	11	11		1,340		1,340
12	Morgan Stanley C.G. Inc	SFP			-1,300			-1,300
13	Nevada Power Company	AD			-98,783		-12,460	-111,243
14	Nevada Power Company	NF	52,053	52,053	301,481			301,481
15	Nevada Power Company	OS					115,171	115,171
16	Nevada Power Company	SFP	129,075	129,075	519,950			519,950
	TOTAL		15,461,404	15,914,125	122,878,918	5,161,909	20,384,518	148,425,345

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	NorthWestern Corp.	NF	13,619	19,006	82,199			82,199
2	NorthWestern Corp.	OS					33,032	33,032
3	NorthWestern Corp.	SFP	138,671	138,671	601,062			601,062
4	Platte River Pwr Auth	LFP	159,142	159,142	849,700			849,700
5	Platte River Pwr Auth	OS					15,707	15,707
6	Portland Gen. Electric	NF	150	150	108			108
7	Portland Gen. Electric	OLF					964	964
8	Portland Gen. Electric	OS					10	10
9	Powerex Corporation	SFP			-4,400			-4,400
10	Public Service Co of CO	LFP	68,905	71,399	1,015,396			1,015,396
11	Public Service Co of CO	NF	39	39	255			255
12	Public Service Co of NM	NF	200	200	1,062			1,062
13	Public Service Co of NM	OS					110	110
14	Puget Sound Energy, Inc	SFP	266,161	266,161	394,001			394,001
15	Salt River Project	NF	7,600	7,600	21,735			21,735
16	Salt River Project	OS					5,324	5,324
	TOTAL		15,461,404	15,914,125	122,878,918	5,161,909	20,384,518	148,425,345

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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)	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	Salt River Project	SFP	6,500	6,500	13,962			13,962
2	Sierra Pacific Power Co	AD			-29,669		-3,701	-33,370
3	Sierra Pacific Power Co	NF	8,482	8,482	43,065			43,065
4	Sierra Pacific Power Co	OS					5,891	5,891
5	Surprise Valley Electr.	OLF					8,279	8,279
6	TransAlta Energy	SFP			-57,109			-57,109
7	Tri-State Gen & Transm	LFP	53,861	56,358	1,015,396			1,015,396
8	Tri-State Gen & Transm	NF	22,796	22,796	102,342			102,342
9	Tri-State Gen & Transm	OS					27,324	27,324
10	Tucson Electric Power	LFP	169,060	169,060	546,739			546,739
11	Tucson Electric Power	NF	3,915	3,915	17,032			17,032
12	Tucson Electric Power	OS					50,377	50,377
13	Tucson Electric Power	SFP	16	16	50			50
14	Westport Field Svc LLC	LFP			-3,705,509			-3,705,509
15	Western Area Power Admn	AD			-979		13,936	12,957
16	Western Area Power Admn	FNS			5,879,221			5,879,221
	TOTAL		15,461,404	15,914,125	122,878,918	5,161,909	20,384,518	148,425,345

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	Western Area Power Admn	LFP	371,322	371,322	1,742,500			1,742,500
2	Western Area Power Admn	NF	241,053	241,053	508,311			508,311
3	Western Area Power Admn	OS	63	63		38,548	1,063,802	1,102,350
4	Western Area Power Admn	OS						
5	Western Area Power Admn	SFP	100,559	100,559	394,904			394,904
6	Reserve						3,950,568	3,950,568
7	Accrual						1,685,254	1,685,254
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		15,461,404	15,914,125	122,878,918	5,161,909	20,384,518	148,425,345

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

Settlement adjustment.

Schedule Page: 332 Line No.: 2 Column: b

Arizona Public Service Company - contract termination dates: January 11, 2041 and May 31, 2047.

Schedule Page: 332 Line No.: 4 Column: g

Ancillary services.

Schedule Page: 332 Line No.: 5 Column: b

Arizona Public Service Company - Legacy contract executed between PacifiCorp and Arizona Public Service Company concerning the exchange of transmission services over agreed-upon facilities (Restated Transmission Service Agreement between PacifiCorp and Arizona Public Service Company, Rate Schedule 436). The contract terminates October 31, 2020. See also page 328, Transmission of electricity for others, in this Form No. 1.

Schedule Page: 332 Line No.: 12 Column: b

Big Horn Rural Electric Company - contract termination date: March 10, 2018.

Schedule Page: 332 Line No.: 12 Column: g

Use of facilities.

Schedule Page: 332 Line No.: 13 Column: b

Settlement adjustment.

Schedule Page: 332 Line No.: 13 Column: g

Ancillary services.

Schedule Page: 332 Line No.: 15 Column: g

Ancillary services.

Schedule Page: 332.1 Line No.: 1 Column: b

Settlement adjustment.

Schedule Page: 332.1 Line No.: 1 Column: e

Prior period adjustments.

Schedule Page: 332.1 Line No.: 1 Column: g

Ancillary services.

Schedule Page: 332.1 Line No.: 3 Column: b

Bonneville Power Administration - contract termination dates: January 1, 2016; July 1, 2016; September 1, 2016; November 1, 2016; December 1, 2016; April 1, 2017; July 1, 2017; November 1, 2017; September 1, 2018; October 1, 2018; December 1, 2018; January 1, 2019; July 1, 2019; September 1, 2019; October 1, 2019; November 1, 2019; December 1, 2019; November 1, 2020; October 1, 2027; November 1, 2033; and evergreen.

Schedule Page: 332.1 Line No.: 5 Column: b

Bonneville Power Administration - contract termination dates: December 31, 2018, September 30, 2027 and evergreen.

Schedule Page: 332.1 Line No.: 5 Column: g

Use of facilities.

Schedule Page: 332.1 Line No.: 6 Column: g

Ancillary services. Use of facilities.

Schedule Page: 332.1 Line No.: 7 Column: b

Bonneville Power Administration - Legacy contract executed between PacifiCorp and Bonneville Power Administration concerning the exchange of transmission services over agreed-upon facilities ("Midpoint-Meridian Transmission Agreement", Rate Schedule 369). This agreement runs concurrently with the AC Intertie Agreement (Rate Schedule 368), which terminates when the facilities subject to that agreement are taken out of service. See also page 328, Transmission of electricity for others, in this Form No. 1.

Schedule Page: 332.1 Line No.: 9 Column: a

This footnote applies to all occurrences of "CA Ind. Sys. Operator" on page 332. Complete name is California Independent System Operator Corporation.

Schedule Page: 332.1 Line No.: 9 Column: b

Settlement adjustment.

Schedule Page: 332.1 Line No.: 9 Column: g
Ancillary services.

Schedule Page: 332.1 Line No.: 10 Column: g
Ancillary services.

Schedule Page: 332.1 Line No.: 12 Column: b
Deseret Generation & Transmission Cooperative - contract termination dates: January 1, 2018 and September 1, 2018.

Schedule Page: 332.1 Line No.: 15 Column: g
Ancillary services.

Schedule Page: 332.2 Line No.: 1 Column: g
Use of facilities.

Schedule Page: 332.2 Line No.: 2 Column: a
Hermiston Generating Company, L.P. operates the Hermiston Generating Plant, which is jointly owned. PacifiCorp owns 50% of the plant.

Schedule Page: 332.2 Line No.: 2 Column: g
Use of facilities.

Schedule Page: 332.2 Line No.: 3 Column: b
Settlement adjustment.

Schedule Page: 332.2 Line No.: 5 Column: b
Idaho Power Company - contract termination dates: April 1, 2025 and July 1, 2025.

Schedule Page: 332.2 Line No.: 7 Column: g
Ancillary services. Use of facilities. PacifiCorp's portion of specified costs of certain facilities.

Schedule Page: 332.2 Line No.: 8 Column: b
Idaho Power Company - Legacy contract (Rate Schedule 427) executed between PacifiCorp and Idaho Power Company concerning the exchange of transmission services over agreed-upon facilities (Draft Transmission Services Agreement between PacifiCorp and Idaho Power Company, Draft 1 – 5/19/95 (“Goshen Agreement”)). Termination of this agreement occurs at the end of the calendar month following the earlier of the effectiveness of a replacement contract, or upon three years written notice of termination as long as PacifiCorp has facilities in place to serve PacifiCorp's Big Grassy load. See also page 328, Transmission of electricity for others, in this Form No. 1.

Schedule Page: 332.2 Line No.: 10 Column: g
Use of facilities.

Schedule Page: 332.2 Line No.: 11 Column: b
Morgan City Corporation - contract termination date: Evergreen.

Schedule Page: 332.2 Line No.: 12 Column: a
This footnote applies to all occurrences of "Morgan Stanley C.G. Inc" on page 332. Complete name is Morgan Stanley Capital Group Inc.

Schedule Page: 332.2 Line No.: 12 Column: e
Reassignment of Bonneville Power Administration transmission.

Schedule Page: 332.2 Line No.: 13 Column: a
This footnote applies to all occurrences of "Nevada Power Company" on page 332. Nevada Power Company is a wholly owned subsidiary of NV Energy, Inc., which is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company, PacifiCorp's indirect parent company.

Schedule Page: 332.2 Line No.: 13 Column: b
Settlement adjustment.

Schedule Page: 332.2 Line No.: 13 Column: e
Prior period adjustments.

Schedule Page: 332.2 Line No.: 13 Column: g
Ancillary services.

Schedule Page: 332.2 Line No.: 15 Column: g
Ancillary services.

Schedule Page: 332.3 Line No.: 2 Column: g

Ancillary services.

Schedule Page: 332.3 Line No.: 4 Column: b

Platte River Power Authority - contract termination date: October 31, 2017.

Schedule Page: 332.3 Line No.: 5 Column: g

Ancillary services.

Schedule Page: 332.3 Line No.: 7 Column: b

Portland General Electric Company - contract termination date: Upon two years written notice.

Schedule Page: 332.3 Line No.: 7 Column: g

Use of facilities.

Schedule Page: 332.3 Line No.: 8 Column: g

Ancillary services.

Schedule Page: 332.3 Line No.: 9 Column: e

Reassignment of Bonneville Power Administration transmission.

Schedule Page: 332.3 Line No.: 10 Column: b

Public Service Company of Colorado - contract termination date: The date that all generating plants comprising PacifiCorp resources associated with this agreement have been retired from service or interests transferred.

Schedule Page: 332.3 Line No.: 13 Column: g

Ancillary services.

Schedule Page: 332.3 Line No.: 16 Column: g

Ancillary services.

Schedule Page: 332.4 Line No.: 2 Column: a

This footnote applies to all occurrences of "Sierra Pacific Power Co" on page 332. Sierra Pacific Power Company is a wholly owned subsidiary of NV Energy, Inc., which is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company, PacifiCorp's indirect parent company.

Schedule Page: 332.4 Line No.: 2 Column: b

Settlement adjustment.

Schedule Page: 332.4 Line No.: 2 Column: e

Prior period adjustments.

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

Surprise Valley Electrification Corp. - contract termination date: Evergreen.

Schedule Page: 332.4 Line No.: 5 Column: g

Use of facilities.

Schedule Page: 332.4 Line No.: 6 Column: a

This footnote applies to all occurrences of "TransAlta Energy" on page 332. Complete name is TransAlta Energy Marketing (U.S.) Inc.

Schedule Page: 332.4 Line No.: 6 Column: e

Reassignment of Bonneville Power Administration transmission.

Schedule Page: 332.4 Line No.: 7 Column: b

Tri-State Generation and Transmission Association, Inc. - contract termination date: The date that all generating plants comprising PacifiCorp resources associated with this agreement have been retired from service or interests transferred.

Schedule Page: 332.4 Line No.: 9 Column: g

Ancillary services.

Schedule Page: 332.4 Line No.: 10 Column: b

Tucson Electric Power Company - contract termination date: December 1, 2015.

Schedule Page: 332.4 Line No.: 12 Column: g

Ancillary services.

Schedule Page: 332.4 Line No.: 14 Column: b

Westport Field Services, LLC - contract termination date: Evergreen.

Schedule Page: 332.4 Line No.: 14 Column: e

Reimbursement for third party services provided.

Schedule Page: 332.4 Line No.: 15 Column: b

Settlement adjustment.

Schedule Page: 332.4 Line No.: 15 Column: e

Prior period adjustments.

Schedule Page: 332.4 Line No.: 15 Column: g

Ancillary services. Use of facilities.

Schedule Page: 332.5 Line No.: 1 Column: b

Western Area Power Administration - contract termination date: May 31, 2022.

Schedule Page: 332.5 Line No.: 3 Column: g

Ancillary services. Use of facilities.

Schedule Page: 332.5 Line No.: 4 Column: b

Western Area Power Administration - Legacy contract (Rate Schedule 664) executed between PacifiCorp and Western Area Power Administration concerning the exchange of transmission services over agreed-upon facilities. The contract terminates 50 years from execution. See also page 328, Transmission of electricity for others, in this Form No. 1.

Schedule Page: 332.5 Line No.: 6 Column: g

Reserve for a contingent liability.

Schedule Page: 332.5 Line No.: 7 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, Transmission of electricity by others, during this period.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2015/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,206,198
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6		
7	Community & Economic Development and	
8	Corporate Memberships & Subscriptions:	
9	Albina Opportunities Corporation	5,000
10	American Leadership Forum of Oregon	5,000
11	American Wind Energy Association	13,779
12	Associated Oregon Industries	28,840
13	Clatsop Economic Development Resources	6,000
14	Economic Development for Central Oregon	8,000
15	Four County Economic Development Corporation	10,000
16	Intermountain Electrical Association	9,000
17	Klamath County Economic Development Association	5,000
18	Oregon Business Association	13,900
19	Oregon Business Council	18,126
20	Oregon Economic Development Association	9,500
21	Oregon State University Utility Pole Research Coop	15,000
22	Pacific Northwest Utilities Conference Committee	76,715
23	Portland Business Alliance	38,200
24	Redmond Economic Development, Inc.	7,000
25	Rocky Mountain Electrical League	18,000
26	Rural Development Initiatives, Inc.	5,500
27	Salt Lake Area Chamber of Commerce	27,000
28	South Coast Development Council, Inc.	10,000
29	Southern Oregon Regional Economic Development, Inc.	6,500
30	Strategic Economic Development Corporation	6,400
31	Utah Governor's Economic Summit	7,000
32	Utah Manufacturers Association	6,600
33	Wyoming Business Alliance	10,000
34	Yakima County Development Association	12,000
35	Other (Individually < $5,000)	149,114
36		
37	Directors' Fees - Regional Advisory Board	15,428
38		
39	Rating Agency and Trustee Fees:	
40	The Bank of New York Mellon	123,085
41	Computershare Shareowner Services, LLC	17,601
42	Fitch, Inc.	39,323
43	Moody's Investors Service, Inc.	137,611
44	Standard and Poor's Financial Services, LLC	216,918
45	U.S. Bank National Association	13,296
46	TOTAL	2,386,938

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
6	Regulatory Asset Amortization:	
7	Generating Plant Liquidated Damages - UT	35,000
8	Generating Plant Liquidated Damages - WY	54,288
9		
10	General:	
11	Other	1,016
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46	TOTAL	2,386,938

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			36,050,777		36,050,777
2	Steam Production Plant	259,770,436				259,770,436
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	33,154,428		281,624		33,436,052
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	126,685,049				126,685,049
7	Transmission Plant	99,238,672				99,238,672
8	Distribution Plant	138,874,436				138,874,436
9	Regional Transmission and Market Operation					
10	General Plant	39,308,259		1,358,159		40,666,418
11	Common Plant-Electric					
12	TOTAL	697,031,280		37,690,560		734,721,840

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	HYDRAULIC PROD.						
13	Klamath River						
14	330.20 OR/CA	41			2.97		4.00
15	330.40 OR/CA	1			2.80		4.00
16	331.00 OR/CA	14,951			8.45		4.00
17	332.00 OR/CA	36,719			7.87		4.00
18	333.00 OR/CA	17,836			7.53		4.00
19	334.00 OR/CA	15,862			8.89		4.00
20	335.00 OR/CA	183			6.13		4.00
21	336.00 OR/CA	2,595			7.41		4.00
22							
23							
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Schedule Page: 336   Line No.: 12   Column: b

Depreciation expense associated with transportation equipment is generally charged to operations and maintenance expense and construction work in progress. During the year ended December 31, 2015, depreciation expense associated with transportation equipment was $14,214,593.

Schedule Page: 336   Line No.: 12   Column: e

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

Schedule Page: 336   Line No.: 13   Column: a

The depreciation rate changes are for the Klamath hydroelectric system’s four mainstem dams (JC Boyle, Iron Gate, Copco No. 1 and Copco No. 2). For further discussion, refer to Note 13 of Notes to Financial Statements in this Form No. 1.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	Utah Public Service Commission:				
2	Annual Fee	5,394,502		5,394,502	
3	Rate Cases and Proceedings		583,941	583,941	
4					
5	Oregon Public Utility Commission:				
6	Annual Fee	3,490,574		3,490,574	
7	Rate Cases and Proceedings		923,066	923,066	
8	Deferred Intervenor Funding Grants				1,069,569
9					
10	Wyoming Public Service Commission:				
11	Annual Fee	1,608,307		1,608,307	
12	Rate Cases and Proceedings		1,545,757	1,545,757	
13					
14	Washington Utilities and Transportation				
15	Commission:				
16	Annual Fee	679,384		679,384	
17	Rate Cases and Proceedings		907,701	907,701	
18					
19	Idaho Public Utilities Commission:				
20	Annual Fee	694,786		694,786	
21	Rate Cases and Proceedings		153,891	153,891	
22	Deferred Intervenor Funding Grants (2)		16,431	16,431	39,031
23					
24	California Public Utilities Commission:				
25	Annual Fee	454		454	
26	Rate Cases and Proceedings		159,391	159,391	
27	Deferred Intervenor Funding Grants				40,347
28					
29	California Environmental Protection Agency:				
30	Industry Compliance Fee	112	10,539	10,651	
31					
32	Multi-State:				
33	Rate Cases and Proceedings		696,394	696,394	
34	Other Regulatory		491,735	491,735	
35					
36	Federal Energy Regulatory Commission:				
37	Annual Fee	1,738,787		1,738,787	
38	Anuual Fee - Hydroelectric Plants	2,362,642		2,362,642	
39	Transmission Rate Cases		175,117	175,117	
40	Other Regulatory		642,175	642,175	
41					
42					
43					
44					
45					
46	TOTAL	15,969,548	6,306,138	22,275,686	1,148,947

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	5,394,502					2
Electric	928	583,941					3
							4
							5
Electric	928	3,490,574					6
Electric	928	923,066					7
			373,389			1,442,958	8
							9
							10
Electric	928	1,608,307					11
Electric	928	1,545,757					12
							13
							14
							15
Electric	928	679,384					16
Electric	928	907,701					17
							18
							19
Electric	928	694,786					20
Electric	928	153,891					21
Electric	928	16,431	4,265	928	16,431	26,865	22
							23
							24
Electric	928	454					25
Electric	928	159,391					26
			59			40,406	27
							28
							29
Electric	928	10,651					30
							31
							32
Electric	928	696,394					33
Electric	928	491,735					34
							35
							36
Electric	928	1,738,787					37
Electric	928	2,362,642					38
Electric	928	175,117					39
Electric	928	642,175					40
							41
							42
							43
							44
							45
		22,275,686	377,713		16,431	1,510,229	46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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 $50,000.)
- (7) Total Cost Incurred

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

Line No.	Classification (a)	Description (b)
1	B. Electric R, D & D Performed Externally:	
2	(1) Research Support	Electric Power Research Institute
3		- Toxic Release Inventory reporting for power plants program
4	(2) Research Support	Edison Electric Institute
5		- Avian Power Line Interaction Committee
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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 (2) [ ] A Resubmission	/ /	End of 2015/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
	15,000	557	15,000		3
					4
10,896	12,180	920,921	23,076		5
					6
					7
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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 (2) [ ] A Resubmission	/ /	End of 2015/Q4

DISTRIBUTION OF SALARIES AND WAGES

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	98,830,452		
4	Transmission	15,085,437		
5	Regional Market			
6	Distribution	34,092,097		
7	Customer Accounts	37,464,104		
8	Customer Service and Informational	6,313,264		
9	Sales			
10	Administrative and General	35,922,353		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	227,707,707		
12	Maintenance			
13	Production	48,867,881		
14	Transmission	10,051,864		
15	Regional Market			
16	Distribution	68,233,277		
17	Administrative and General	1,822,203		
18	TOTAL Maintenance (Total of lines 13 thru 17)	128,975,225		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	147,698,333		
21	Transmission (Enter Total of lines 4 and 14)	25,137,301		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	102,325,374		
24	Customer Accounts (Transcribe from line 7)	37,464,104		
25	Customer Service and Informational (Transcribe from line 8)	6,313,264		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	37,744,556		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	356,682,932		356,682,932
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 (2) [ ] A Resubmission	/ /	End of 2015/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

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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 47)			
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)	356,682,932		356,682,932
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	151,032,878		151,032,878
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	151,032,878		151,032,878
72	Plant Removal (By Utility Departments)			
73	Electric Plant	9,252,820		9,252,820
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	9,252,820		9,252,820
77	Other Accounts (Specify, provide details in footnote):			
78	Fuel Stock	2,722,964		2,722,964
79	Miscellaneous Other Income Deductions	612,988		612,988
80	Miscellaneous Non-Operating and Non-Utility	667,582		667,582
81	Charges to Affiliates	3,674,951		3,674,951
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	7,678,485		7,678,485
96	TOTAL SALARIES AND WAGES	524,647,115		524,647,115

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

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

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	312	590,931	1,181,543	1,177,243
3	Net Sales (Account 447)	(538,380)	(985,233)	(1,667,302)	(2,057,804)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7	Energy Imbalance Market (Account 555)	(2,444,386)	(11,341,992)	(18,294,857)	(22,261,762)
8					
9					
10					
11					
12					
13					
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42					
43					
44					
45					
46	TOTAL	(2,982,454)	(11,736,294)	(18,780,616)	(23,142,323)

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				145,271,733	MWh	12,494,858
2	Reactive Supply and Voltage	126,182,822	MWh	8,497,326	136,672,907	MWh	9,213,724
3	Regulation and Frequency Response	97,899,037	MWh	32,998,011	107,771,335	MWh	36,316,840
4	Energy Imbalance				384,200	MWh	11,740,994
5	Operating Reserve - Spinning	121,970,891	MWh	47,568,647	128,234,549	MWh	50,054,836
6	Operating Reserve - Supplement	47,568,647	MWh	41,470,103	50,785,942	MWh	42,599,461
7	Other						
8	Total (Lines 1 thru 7)	393,621,397		130,534,087	569,120,666		162,420,713

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	14,999	2	1800	8,506	128	3,358		1,386	1,621
2	February	13,980	23	800	8,246	158	3,358		742	1,476
3	March	14,507	4	800	8,124	136	3,358		1,411	1,478
4	Total for Quarter 1				24,876	422	10,074		3,539	4,575
5	April	13,243	15	800	7,615	122	3,358		672	1,476
6	May	13,109	31	1800	7,767	101	3,358		356	1,527
7	June	18,413	29	1600	10,906	159	3,531		1,593	2,224
8	Total for Quarter 2				26,288	382	10,247		2,621	5,227
9	July	19,163	2	1600	10,809	144	3,531		2,532	2,147
10	August	17,449	13	1600	9,946	146	3,531		1,742	2,084
11	September	16,151	1	1600	9,093	131	3,505		1,430	1,992
12	Total for Quarter 3				29,848	421	10,567		5,704	6,223
13	October	14,131	1	1700	8,109	103	3,489		633	1,797
14	November	14,532	30	1800	8,795	142	3,358		679	1,558
15	December	14,086	28	1800	8,530	140	3,363		412	1,641
16	Total for Quarter 4				25,434	385	10,210		1,724	4,996
17	Total Year to Date/Year				106,446	1,610	41,098		13,588	21,021

Schedule Page: 400 Line No.: 1 Column: d
Pacific Standard Time.

Schedule Page: 400 Line No.: 2 Column: d
Pacific Standard Time.

Schedule Page: 400 Line No.: 3 Column: d
Pacific Standard Time.

Schedule Page: 400 Line No.: 5 Column: d
Pacific Daylight Time.

Schedule Page: 400 Line No.: 6 Column: d
Pacific Daylight Time.

Schedule Page: 400 Line No.: 7 Column: d
Pacific Daylight Time.

Schedule Page: 400 Line No.: 9 Column: d
Pacific Daylight Time.

Schedule Page: 400 Line No.: 10 Column: d
Pacific Daylight Time.

Schedule Page: 400 Line No.: 11 Column: d
Pacific Daylight Time.

Schedule Page: 400 Line No.: 13 Column: d
Pacific Daylight Time.

Schedule Page: 400 Line No.: 14 Column: d
Pacific Standard Time.

Schedule Page: 400 Line No.: 15 Column: d
Pacific Standard Time.

Schedule Page: 400 Line No.: 17 Column: e
Year-to-date 2015 Net System Load information was compiled using material and/or scheduling data. Reflects actual peak net system load for self at time of Transmission System Peak. Peak load includes behind-the-meter generation.

Schedule Page: 400 Line No.: 17 Column: f
Year-to-date 2015 Net System Load information was compiled using metering and/or scheduling data. Reflects actual peak of customers' load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 17 Column: g
Year-to-date 2015 Net System Load information was compiled using reservations in OASIS at time of Transmission System Peak. Long-term firm point-to-point reservations have been adjusted so that the monthly megawatt reservations represent an amount at system input as measured by the transmission system loss factor. This adjustment has been made to ensure that transmission rates are designed fairly and in a non-discriminatory manner and is consistent with the system input measurement utilized for other long-term firm users of PacifiCorp's transmission system, including network service.

Schedule Page: 400 Line No.: 17 Column: i
Year-to-date 2015 Net System Load information was compiled using reservations in OASIS at time of Transmission System Peak.

Schedule Page: 400 Line No.: 17 Column: j
Year-to-date 2015 Net System Load information was compiled using metering, scheduling and/or contractual data. Reflects actual peak and/or contractual demands of customers' load at time of Transmission System Peak.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	54,641,212
3	Steam	44,612,067			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	128,557
5	Hydro-Conventional	2,915,015			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	8,760,894
7	Other	8,806,733			
8	Less Energy for Pumping	2,776	25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	56,331,039	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	122,063
10	Purchases	11,948,954	27	Total Energy Losses	4,298,494
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	67,951,220
12	Received	4,930,109			
13	Delivered	4,919,231			
14	Net Exchanges (Line 12 minus line 13)	10,878			
15	Transmission For Other (Wheeling)				
16	Received	13,260,949			
17	Delivered	13,147,879			
18	Net Transmission for Other (Line 16 minus line 17)	113,070			
19	Transmission By Others Losses	-452,721			
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	67,951,220			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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 in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-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	6,048,460	821,842	8,309	2	1800 PST
30	February	5,326,720	904,128	8,038	23	0800 PST
31	March	5,588,337	858,756	7,865	4	0800 PST
32	April	5,251,800	682,185	7,417	15	0800 PDT
33	May	5,067,454	423,611	7,476	31	1800 PDT
34	June	5,798,377	464,328	10,621	30	1700 PDT
35	July	6,069,805	565,913	10,494	1	1500 PDT
36	August	6,025,426	668,232	9,631	13	1700 PDT
37	September	5,547,345	831,497	8,712	1	1600 PDT
38	October	5,405,659	830,199	7,824	1	1700 PDT
39	November	5,559,595	717,629	8,550	30	1800 PST
40	December	6,262,242	992,574	8,333	14	1800 PST
41	TOTAL	67,951,220	8,760,894			

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) X An Original (2) _ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 401 Line No.: 26 Column: b

For metered locations only.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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)	188.64			414.00		
6	Net Peak Demand on Plant - MW (60 minutes)	176			386		
7	Plant Hours Connected to Load	2517			7186		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	172			395		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	21			0		
12	Net Generation, Exclusive of Plant Use - KWh	392328000			2499474000		
13	Cost of Plant: Land and Land Rights	956546			2635317		
14	Structures and Improvements	155722			64422937		
15	Equipment Costs	5162376			475530722		
16	Asset Retirement Costs	7036834			19325010		
17	Total Cost	13311478			561913986		
18	Cost per KW of Installed Capacity (line 17/5) Including	70.5655			1357.2802		
19	Production Expenses: Oper, Supv, & Engr	32746			1439756		
20	Fuel	8451578			61816014		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	464908			7969920		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	638918			717209		
26	Misc Steam (or Nuclear) Power Expenses	910649			1021693		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			2291276		
30	Maintenance of Structures	137083			1392665		
31	Maintenance of Boiler (or reactor) Plant	699871			3211628		
32	Maintenance of Electric Plant	86810			752056		
33	Maintenance of Misc Steam (or Nuclear) Plant	60686			3230982		
34	Total Production Expenses	11483249			83843199		
35	Expenses per Net KWh	0.0293			0.0335		
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	184303	218	0	1454545	4830	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12254	138000	0	9168	126670	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	44.169	124.810	0.000	39.786	112.700	0.000
41	Average Cost of Fuel per Unit Burned	45.709	124.810	0.000	42.124	112.700	0.000
42	Average Cost of Fuel Burned per Million BTU	1.865	21.536	1.871	2.297	21.184	2.316
43	Average Cost of Fuel Burned per KWh Net Gen	0.021	0.000	0.021	0.025	0.000	0.025
44	Average BTU per KWh Net Generation	11512.654	3.220	11515.874	10670.004	10.281	10680.285

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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
155.61			172.13			816.77			5
163			164			719			6
8754			8683			8760			7
0			0			0			8
148			165			760			9
0			0			0			10
0			0			189			11
1192557000			1068985000			5140970000			12
1788644			137086			10449793			13
61015586			38199720			155245209			14
165015529			143059721			853217693			15
8592613			35149			17242673			16
236412372			181431676			1036155368			17
1519.2621			1054.0387			1268.6012			18
36076			329648			392819			19
17911181			19435541			59636026			20
0			0			0			21
1069424			1715067			4380486			22
0			0			0			23
0			0			0			24
89118			734477			0			25
1869058			1010808			16663534			26
22399			0			55062			27
0			0			0			28
271598			748176			0			29
471471			401781			2425506			30
2195492			2985580			10563237			31
295709			1482574			7535947			32
302598			849885			1327573			33
24534124			29693537			102980190			34
0.0206			0.0278			0.0200			35
Coal	Oil	Composite	Coal	Oil	Composite	Coal	Oil	Composite	36
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
751369	1106	0	526537	183	0	3570193	16464	0	38
8410	140000	0	10104	133693	0	8042	138000	0	39
20.914	115.158	0.000	35.521	126.581	0.000	16.213	87.006	0.000	40
23.669	115.158	0.000	36.663	126.581	0.000	16.303	87.006	0.000	41
1.407	19.584	1.416	1.814	22.536	1.826	1.014	15.011	1.037	42
0.015	0.000	0.015	0.018	0.000	0.018	0.011	0.000	0.011	43
10598.013	5.451	10603.464	9953.236	0.963	9954.199	11169.956	18.562	11188.518	44

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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)			81.37			457.73
6	Net Peak Demand on Plant - MW (60 minutes)			448			423
7	Plant Hours Connected to Load			8551			8493
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			78			418
10	When Limited by Condenser Water			0			0
11	Average Number of Employees			0			0
12	Net Generation, Exclusive of Plant Use - KWh			554930000			3002762000
13	Cost of Plant: Land and Land Rights			683069			9688261
14	Structures and Improvements			17685365			63296254
15	Equipment Costs			85571224			378449444
16	Asset Retirement Costs			532363			2501143
17	Total Cost			104472021			453935102
18	Cost per KW of Installed Capacity (line 17/5) Including			1283.9132			991.7093
19	Production Expenses: Oper, Supv, & Engr			189454			0
20	Fuel			13792469			61664773
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			905136			6687851
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			170583			0
26	Misc Steam (or Nuclear) Power Expenses			618418			-1109143
27	Rents			0			0
28	Allowances			0			0
29	Maintenance Supervision and Engineering			249034			0
30	Maintenance of Structures			496638			2778774
31	Maintenance of Boiler (or reactor) Plant			1344748			6468359
32	Maintenance of Electric Plant			529700			1242405
33	Maintenance of Misc Steam (or Nuclear) Plant			539558			382638
34	Total Production Expenses			18835738			78115657
35	Expenses per Net KWh			0.0339			0.0260
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	264015	297	0	1364974	1954	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11394	137269	0	11205	138000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	48.636	115.441	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	52.005	115.441	0.000	45.034	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.282	20.024	2.292	2.010	17.135	2.015
43	Average Cost of Fuel Burned per KWh Net Gen	0.025	0.000	0.025	0.020	0.000	0.020
44	Average BTU per KWh Net Generation	10841.312	3.089	10884.401	10187.222	3.771	10190.993

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

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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
		294.46			495.59			1247.78	5
		277			475			1366	6
		7889			8416			8760	7
		0			0			0	8
		269			471			1158	9
		0			0			0	10
		0			0			219	11
		1959744000			3373107000			8335613000	12
		9688261			10274569			29651091	13
		52603034			91236560			207135848	14
		245411405			431029104			1054889953	15
		2501143			2501143			7503429	16
		310203843			535041376			1299180321	17
		1053.4668			1079.6049			1041.1934	18
		0			0			0	19
		39087715			68317656			169070144	20
		0			0			0	21
		4609812			7173271			18470934	22
		0			0			0	23
		0			0			0	24
		0			331			331	25
		-9619104			-372129			-11100376	26
		0			0			0	27
		0			0			0	28
		0			0			0	29
		2455295			2803307			8037376	30
		8792854			8496412			23757625	31
		2483602			1316653			5042660	32
		382227			448413			1213278	33
		48192401			88183914			214491972	34
		0.0246			0.0261			0.0257	35
Coal	Oil	Composite	Coal	Oil	Composite	Coal	Oil	Composite	36
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
869168	919	0	1499018	6882	0	3733160	9755	0	38
11470	138000	0	11315	138000	0	11311	138000	0	39
0.000	0.000	0.000	0.000	0.000	0.000	41.695	99.733	0.000	40
44.859	0.000	0.000	45.120	0.000	0.000	45.028	99.733	0.000	41
1.956	18.283	1.960	1.994	17.084	2.012	1.990	17.207	2.001	42
0.020	0.000	0.020	0.020	0.000	0.020	0.020	0.000	0.020	43
10174.093	2.719	10176.812	10056.667	11.825	10068.492	10131.305	6.783	10138.088	44

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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			1550.65
6	Net Peak Demand on Plant - MW (60 minutes)			904			1429
7	Plant Hours Connected to Load			8760			8760
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			909			1415
10	When Limited by Condenser Water			0			0
11	Average Number of Employees			162			340
12	Net Generation, Exclusive of Plant Use - KWh			5988318000			9195773000
13	Cost of Plant: Land and Land Rights			2379205			1209912
14	Structures and Improvements			120076780			144935694
15	Equipment Costs			730851901			1098112165
16	Asset Retirement Costs			10624210			19511387
17	Total Cost			863932096			1263769158
18	Cost per KW of Installed Capacity (line 17/5) Including			867.4017			814.9932
19	Production Expenses: Oper, Supv, & Engr			7391			12558828
20	Fuel			158215307			252108692
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			12982916			23021177
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			0			0
26	Misc Steam (or Nuclear) Power Expenses			-21538635			-23806621
27	Rents			0			291223
28	Allowances			0			0
29	Maintenance Supervision and Engineering			2149966			780274
30	Maintenance of Structures			3248282			12048778
31	Maintenance of Boiler (or reactor) Plant			11976826			23290438
32	Maintenance of Electric Plant			3101246			10156475
33	Maintenance of Misc Steam (or Nuclear) Plant			936785			1865553
34	Total Production Expenses			171080084			312314817
35	Expenses per Net KWh			0.0286			0.0340
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	2678630	4671	0	5193483	12367	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11439	138000	0	9175	138000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	47.650	99.623	0.000	45.168	114.686	0.000
41	Average Cost of Fuel per Unit Burned	58.892	99.623	0.000	48.270	114.686	0.000
42	Average Cost of Fuel Burned per Million BTU	2.574	17.188	2.581	2.631	19.787	2.644
43	Average Cost of Fuel Burned per KWh Net Gen	0.026	0.000	0.026	0.027	0.000	0.027
44	Average BTU per KWh Net Generation	10233.120	4.521	10237.641	10363.029	7.795	10370.824

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

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Plant Name: *Naughton* (d)	Plant Name: *Wyodak* (e)	Plant Name: *Gadsby Steam* (f)	Line No.
Steam	Steam	Steam	1
Outdoor Boiler	Conventional	Outdoor	2
1963	1978	1951	3
1971	1978	1955	4
707.20	289.66	251.64	5
693	274	173	6
8759	8154	1832	7
0	0	0	8
637	266	238	9
0	0	0	10
125	62	36	11
4899321000	2032298000	88928000	12
1007450	210526	1252090	13
118439921	51320998	15101604	14
652859048	399209035	67279520	15
47409550	652977	1132809	16
819715969	451393536	84766023	17
1159.1006	1558.3565	336.8543	18
392979	28095	79707	19
97849265	29253664	6252323	20
0	0	0	21
7959262	4558432	117579	22
0	0	0	23
0	0	0	24
1012	0	0	25
9107751	3170165	3866855	26
964	18807	0	27
0	0	0	28
2024615	0	0	29
1243854	292258	155804	30
10863884	2947252	988303	31
3313923	928039	1322296	32
1100841	124077	253266	33
133858350	41320789	13036133	34
0.0273	0.0203	0.1466	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
2662827	86236	0	1536071	3715	0	1443258	0	0	38
9946	1048	0	8054	138000	0	1050	0	0	39
36.530	6.702	0.000	18.546	120.266	0.000	4.332	0.000	0.000	40
36.529	6.702	0.000	18.754	120.266	0.000	4.332	0.000	0.000	41
1.836	6.392	1.844	1.164	20.750	1.181	4.127	0.000	0.000	42
0.020	0.000	0.020	0.014	0.000	0.014	0.070	0.000	0.000	43
10811.501	18.455	10829.956	12175.384	10.594	12185.978	17035.332	0.000	0.000	44

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Line No.	Item (a)	Plant Name: *Hermiston* (b)			Plant Name: *Blundell* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Combined Cycle			Steam - Geothermal		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor			Indoor		
3	Year Originally Constructed	1996			1984		
4	Year Last Unit was Installed	1996			2007		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	279.56			38.10		
6	Net Peak Demand on Plant - MW (60 minutes)	250			36		
7	Plant Hours Connected to Load	7944			8508		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	231			32		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			22		
12	Net Generation, Exclusive of Plant Use - KWh	1202753000			259703000		
13	Cost of Plant: Land and Land Rights	842245			41195596		
14	Structures and Improvements	12844330			8295518		
15	Equipment Costs	162916793			101447600		
16	Asset Retirement Costs	407646			2062367		
17	Total Cost	177011014			153001081		
18	Cost per KW of Installed Capacity (line 17/5) Including	633.1772			4015.7764		
19	Production Expenses: Oper, Supv, & Engr	0			29512		
20	Fuel	26628707			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			998804		
23	Steam From Other Sources	0			3980975		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	7720793			0		
26	Misc Steam (or Nuclear) Power Expenses	0			2631758		
27	Rents	0			6247		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			313458		
31	Maintenance of Boiler (or reactor) Plant	0			207042		
32	Maintenance of Electric Plant	0			287655		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			89154		
34	Total Production Expenses	34349500			8544605		
35	Expenses per Net KWh	0.0286			0.0329		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas					
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF					
38	Quantity (Units) of Fuel Burned	8864789	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1033	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.004	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	3.004	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.908	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.022	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	7612.807	0.000	0.000	0.000	0.000	0.000

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Plant Name: *Camas Co-Gen* (d)	Plant Name: *Chehalis* (e)	Plant Name: *Gadsby Peakers* (f)	Line No.
Steam	Combined Cycle	Gas Turbine	1
Outdoor Boiler	Outdoor	Outdoor	2
1996	2003	2002	3
1996	2003	2002	4
61.50	593.30	181.05	5
17	490	123	6
4690	3938	1516	7
0	0	0	8
10	477	119	9
0	0	0	10
0	19	0	11
45774000	1092993000	34867000	12
0	1973791	0	13
0	24026885	4273000	14
0	321726455	78066278	15
0	1030777	0	16
0	348757908	82339278	17
0.0000	587.8273	454.7875	18
0	151945	0	19
0	36529831	3233408	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	2245195	632475	25
362000	706444	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	28021	184185	30
0	0	0	31
0	6497288	650458	32
0	0	164169	33
362000	46158724	4864695	34
0.0079	0.0422	0.1395	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
			Gas			Gas			36
			MCF			MCF			37
0	0	0	7813967	0	0	563090	0	0	38
0	0	0	1074	0	0	1052	0	0	39
0.000	0.000	0.000	4.675	0.000	0.000	5.741	0.000	0.000	40
0.000	0.000	0.000	4.675	0.000	0.000	5.741	0.000	0.000	41
0.000	0.000	0.000	4.354	0.000	0.000	5.460	0.000	0.000	42
0.000	0.000	0.000	0.033	0.000	0.000	0.093	0.000	0.000	43
0.000	0.000	0.000	7676.629	0.000	0.000	16983.796	0.000	0.000	44

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Line No.	Item (a)	Plant Name: *Currant Creek* (b)			Plant Name: *Lake Side* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Combined Cycle			Combined Cycle		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor			Outdoor		
3	Year Originally Constructed	2005			2007		
4	Year Last Unit was Installed	2006			2007		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	566.90			591.30		
6	Net Peak Demand on Plant - MW (60 minutes)	522			555		
7	Plant Hours Connected to Load	8281			7060		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	524			546		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	21			34		
12	Net Generation, Exclusive of Plant Use - KWh	2257106000			2272420000		
13	Cost of Plant: Land and Land Rights	3403277			14532275		
14	Structures and Improvements	44164698			35465598		
15	Equipment Costs	324856743			337400017		
16	Asset Retirement Costs	134848			0		
17	Total Cost	372559566			387397890		
18	Cost per KW of Installed Capacity (line 17/5) Including	657.1875			655.1630		
19	Production Expenses: Oper, Supv, & Engr	86128			61947		
20	Fuel	69244606			66140092		
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	1910526			2814096		
26	Misc Steam (or Nuclear) Power Expenses	690551			583997		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	440419			2830122		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	1079804			3661198		
33	Maintenance of Misc Steam (or Nuclear) Plant	21504			17480		
34	Total Production Expenses	73473538			76108932		
35	Expenses per Net KWh	0.0326			0.0335		
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	16300845	0	0	15150724	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1037	0	0	1042	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	4.248	0.000	0.000	4.365	0.000	0.000
41	Average Cost of Fuel per Unit Burned	4.248	0.000	0.000	4.365	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	4.095	0.000	0.000	4.190	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.031	0.000	0.000	0.029	0.000	0.000
44	Average BTU per KWh Net Generation	7492.601	0.000	0.000	6946.098	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 (2) [ ] A Resubmission	/ /	End of 2015/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 2* (d)	Plant Name: (e)	Plant Name: (f)	Line No.
Combined Cycle			1
Outdoor			2
2014			3
2014			4
655.20	0.00	0.00	5
617	0	0	6
7497	0	0	7
0	0	0	8
631	0	0	9
0	0	0	10
0	0	0	11
2276854000	0	0	12
16794626	0	0	13
53195814	0	0	14
568560609	0	0	15
0	0	0	16
638551049	0	0	17
974.5895	0	0	18
71591	0	0	19
70649551	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
2414966	0	0	25
617666	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
745262	0	0	30
0	0	0	31
663174	0	0	32
16896	0	0	33
75179106	0	0	34
0.0330	0.0000	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Gas									36
MCF									37
16234720	0	0	0	0	0	0	0	0	38
1042	0	0	0	0	0	0	0	0	39
4.352	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
4.352	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
4.177	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.031	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
7428.486	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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

The Carbon Plant was idled in April 2015 and retired in December 2015 to comply with the Mercury and Air Toxics Standards requirements and other environmental regulations as well as in conformance with Utah's Regional Haze State Implementation Plan.

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

The Cholla Plant is operated by Arizona Public Service Company and is jointly owned. PacifiCorp owns 100% of Unit No. 4 and 36.66% of common facilities. Data reported in column (c) represents PacifiCorp's share.

Schedule Page: 403 Line No.: -1 Column: d

The Colstrip Plant is operated by Talen Montana, LLC and is jointly owned. PacifiCorp owns a 10.0% share of Colstrip Plant Unit Nos. 3 and 4. Data reported in column (d) represents PacifiCorp's share.

Schedule Page: 403 Line No.: -1 Column: e

The Craig Plant is operated by Tri-State Generation and Transmission Association and is jointly owned. PacifiCorp owns a 19.28% share of Craig Plant Unit Nos. 1 and 2 and 12.86% of common facilities. Data in column (e) represents PacifiCorp's share.

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

PacifiCorp does not have employees at the Cholla Plant.

Schedule Page: 403 Line No.: 11 Column: d

PacifiCorp does not have employees at the Colstrip Plant.

Schedule Page: 403 Line No.: 11 Column: e

PacifiCorp does not have employees at the Craig Plant.

Schedule Page: 403 Line No.: 20 Column: e

Amount includes intercompany profits.

Schedule Page: 402.1 Line No.: -1 Column: b

The Hayden Plant is operated by Public Service Company of Colorado and is jointly owned. PacifiCorp owns a 24.5% (45 MW) share of Hayden Unit No. 1, a 12.6% (33 MW) share of Hayden Unit No. 2 and 17.5% of common facilities. Data reported in column (b) represents PacifiCorp's share.

Schedule Page: 402.1 Line No.: -1 Column: c

Hunter Unit No. 1 is operated by PacifiCorp and is jointly owned by PacifiCorp and Utah Municipal Power Agency with an undivided interest of 93.75% and 6.25%, respectively. Data reported in column (c) represents PacifiCorp's share. Costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this unit for calendar year 2015 were $1.4 million and were primarily credited to Account 506, Miscellaneous steam power expenses.

Schedule Page: 403.1 Line No.: -1 Column: d

Hunter Unit No. 2 is operated by PacifiCorp and is jointly owned by PacifiCorp, Deseret Power Electric Cooperative and Utah Associated Municipal Power Systems, each with an undivided interest of 60.31%, 25.108% and 14.582%, respectively. Data reported in column (d) represents PacifiCorp's share. Costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this unit for calendar year 2015 were $11.4 million and were primarily credited to Account 506, Miscellaneous steam power expenses.

Schedule Page: 403.1 Line No.: -1 Column: f

Refer to plant statistics for each Hunter Unit Nos. 1, 2 and 3 on pages 402.1 and 403.1.

Schedule Page: 402.1 Line No.: 11 Column: b

PacifiCorp does not have employees at the Hayden Plant.

Schedule Page: 402.1 Line No.: 11 Column: c

Refer to Hunter - Total Plant on page 403.1 for the average number of employees.

Schedule Page: 403.1 Line No.: 11 Column: d

Refer to Hunter - Total Plant on page 403.1 for the average number of employees.

Schedule Page: 403.1 Line No.: 11 Column: e

Refer to Hunter - Total Plant on page 403.1 for the average number of employees.

Schedule Page: 402.2 Line No.: -1 Column: c

The Jim Bridger Plant is operated by PacifiCorp and is jointly owned by PacifiCorp and Idaho Power Company with an undivided interest of 66 2/3% and 33 1/3%, respectively. Data reported in column (c) represents PacifiCorp's share. Costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this plant for calendar year 2015 were $29.5 million and were primarily credited to Account 506, Miscellaneous steam power expenses.

Schedule Page: 403.2 Line No.: -1 Column: d

With the intent of allowing Naughton Unit No. 3 to continue to serve customer load needs beyond its currently prescribed year end December 31, 2017 compliance deadline, PacifiCorp is considering environmental compliance alternatives to accelerated retirement which include reassessment of traditional natural gas conversion and deployment of other emerging technologies.

Schedule Page: 403.2 Line No.: -1 Column: e

The Wyodak Plant is operated by PacifiCorp and is jointly owned by PacifiCorp and Black Hills Corporation with an undivided interest of 80% and 20%, respectively. Data in column (e) represents PacifiCorp's share. Costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this plant for calendar year 2015 were $4.0 million and were primarily credited to Account 506, Miscellaneous steam power expenses.

Schedule Page: 402.2 Line No.: 20 Column: c

Amount includes intercompany profits.

Schedule Page: 402.3 Line No.: -1 Column: b

The Hermiston Plant is operated by Hermiston Generating Company, L.P. and is jointly owned. PacifiCorp owns a 50.0% share of the Hermiston Plant. Data reported in column (b) represents PacifiCorp's share. See page 326, Purchased Power, in this Form No. 1 for further information on Hermiston Generating Company, L.P.

Schedule Page: 402.3 Line No.: -1 Column: c

All or some of the renewable energy attributes associated with generation from the Blundell generating facility may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 403.3 Line No.: -1 Column: d

In December 2015, PacifiCorp sold to Georgia-Pacific Consumer Products LLC, the steam turbine generator and associated systems directly related to the operation of the Camas Co-Generation unit at Georgia-Pacific Corporation's Camas, Washington paper mill. Refer to Item 3 in Important Changes During the Year in this Form No. 1.

Schedule Page: 402.3 Line No.: 11 Column: b

PacifiCorp does not have employees at the Hermiston Plant.

Schedule Page: 403.3 Line No.: 11 Column: d

PacifiCorp does not have employees at the Camas Co-Generation unit at Georgia-Pacific Corporation's Camas, Washington paper mill.

Schedule Page: 403.3 Line No.: 11 Column: f

Refer to the Gadsby Steam Plant on page 403.2 for the average number of employees.

Schedule Page: 403.4 Line No.: 11 Column: d

Refer to the Lake Side Plant on page 402.4 for the average number of employees.

Schedule Page: 402 Line No.: 36 Column: b2

Carbon - Fuel oil is used for start-up purposes.

Schedule Page: 402 Line No.: 36 Column: c2

Cholla - Fuel oil is used for start-up purposes.

Schedule Page: 402 Line No.: 36 Column: d2

Colstrip - Fuel oil is used for start-up purposes.

Schedule Page: 402 Line No.: 36 Column: e2

Craig - 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: b2

Hayden - Fuel oil is used for start-up purposes.

Schedule Page: 402.1 Line No.: 36 Column: c2

Hunter Unit No. 1 - Fuel oil is used for start-up purposes.

Schedule Page: 402.1 Line No.: 36 Column: d2

Hunter Unit No. 2 - Fuel oil is used for start-up purposes.

Schedule Page: 402.1 Line No.: 36 Column: e2

Hunter Unit No. 3 - Fuel oil is used for start-up purposes.

Schedule Page: 402.1 Line No.: 36 Column: f2

Hunter - Total Plant - 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: c2

Jim Bridger - Fuel oil is used for start-up purposes.

Schedule Page: 402.2 Line No.: 36 Column: d2

Naughton - Fuel oil is used for start-up purposes.

Schedule Page: 402.2 Line No.: 36 Column: e2

Wyodak - Fuel oil 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 (2) [ ] A Resubmission	/ /	End of 2015/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 2082 Plant Name: Copco No. 1 (b)	FERC Licensed Project No. 2082 Plant Name: Copco No. 2 (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1918	1925
4	Year Last Unit was Installed	1922	1925
5	Total installed cap (Gen name plate Rating in MW)	20.00	27.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	28	31
7	Plant Hours Connect to Load	7,196	6,947
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	60,539,000	77,098,000
13	Cost of Plant		
14	Land and Land Rights	107,019	20,914
15	Structures and Improvements	1,700,478	2,336,557
16	Reservoirs, Dams, and Waterways	2,936,826	2,954,724
17	Equipment Costs	5,355,643	10,431,454
18	Roads, Railroads, and Bridges	133,348	479,588
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	10,233,314	16,223,237
21	Cost per KW of Installed Capacity (line 20 / 5)	511.6657	600.8606
22	Production Expenses		
23	Operation Supervision and Engineering	21,449	26,450
24	Water for Power	0	0
25	Hydraulic Expenses	3,821	5,159
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	992,745	1,313,392
28	Rents	60,631	82,487
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	10,312	9,968
31	Maintenance of Reservoirs, Dams, and Waterways	9,816	10,329
32	Maintenance of Electric Plant	148,372	133,848
33	Maintenance of Misc Hydraulic Plant	15,845	21,391
34	Total Production Expenses (total 23 thru 33)	1,262,991	1,603,024
35	Expenses per net KWh	0.0209	0.0208

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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 Plant Name: Clearwater No. 1 (d)	FERC Licensed Project No. 1927 Plant Name: Clearwater No. 2 (e)	FERC Licensed Project No. 2420 Plant Name: Cutler (f)	Line No.
Run-of-River	Run-of-River	Storage	1
Outdoor	Outdoor	Conventional	2
1953	1953	1927	3
1953	1953	1927	4
15.00	26.00	30.00	5
10	17	23	6
8,170	8,521	5,506	7
			8
18	31	29	9
18	31	29	10
1	1	3	11
31,575,000	32,142,000	35,726,000	12
			13
0	0	3,511,105	14
1,477,267	2,354,538	3,978,099	15
5,126,842	14,779,679	9,178,322	16
1,327,300	2,160,625	14,696,726	17
50,817	250,151	572,059	18
0	0	0	19
7,982,226	19,544,993	31,936,311	20
532.1484	751.7305	1,064.5437	21
			22
16,614	29,817	93,553	23
807	1,399	0	24
40,193	69,669	91,134	25
0	0	0	26
282,538	476,569	1,094,323	27
61,624	106,815	11,841	28
0	0	0	29
33,440	34,321	3,908	30
21,950	16,533	40,950	31
93,583	18,421	34,657	32
51,892	91,082	284,877	33
602,641	844,626	1,655,243	34
0.0191	0.0263	0.0463	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 1927 Plant Name: Fish Creek (b)	FERC Licensed Project No. 20 Plant Name: Grace (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1952	1908
4	Year Last Unit was Installed	1952	1923
5	Total installed cap (Gen name plate Rating in MW)	11.00	33.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	11	27
7	Plant Hours Connect to Load	1,518	7,499
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	7,941,000	63,251,000
13	Cost of Plant		
14	Land and Land Rights	0	62,169
15	Structures and Improvements	1,725,441	2,090,821
16	Reservoirs, Dams, and Waterways	12,371,658	11,163,768
17	Equipment Costs	2,942,830	4,867,577
18	Roads, Railroads, and Bridges	533,015	341,093
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	17,572,944	18,525,428
21	Cost per KW of Installed Capacity (line 20 / 5)	1,597.5404	561.3766
22	Production Expenses		
23	Operation Supervision and Engineering	13,318	107,598
24	Water for Power	592	0
25	Hydraulic Expenses	29,475	35,837
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	240,959	1,320,734
28	Rents	45,191	11,876
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	19,333	56,692
31	Maintenance of Reservoirs, Dams, and Waterways	2,371	110,043
32	Maintenance of Electric Plant	7,665	83,419
33	Maintenance of Misc Hydraulic Plant	38,054	39,677
34	Total Production Expenses (total 23 thru 33)	396,958	1,765,876
35	Expenses per net KWh	0.0500	0.0279

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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 Plant Name: Iron Gate (d)	FERC Licensed Project No. 2082 Plant Name: JC Boyle (e)	FERC Licensed Project No. 1927 Plant Name: Lemolo No. 1 (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
19	79	31	6
8,422	4,991	8,674	7
			8
19	83	32	9
19	83	32	10
1	2	1	11
82,043,000	160,121,000	123,550,000	12
			13
341,706	25,845	0	14
7,367,591	3,528,960	2,708,566	15
15,256,322	15,570,539	15,724,314	16
2,724,771	15,364,071	6,717,294	17
1,095,742	886,710	488,877	18
0	0	0	19
26,786,132	35,376,125	25,639,051	20
1,488.1184	361.0546	801.4708	21
			22
1,437,841	194,434	34,253	23
0	0	1,721	24
20,379	5,772	85,719	25
0	0	0	26
905,002	764,435	615,413	27
54,568	40,950	131,424	28
0	0	0	29
5,829	14,259	42,273	30
8,916	32,540	14,697	31
109,859	20,795	21,379	32
14,261	40,218	111,868	33
2,556,655	1,113,403	1,058,747	34
0.0312	0.0070	0.0086	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 1927 Plant Name: Lemolo No. 2 (b)	FERC Licensed Project No. 935 Plant Name: Merwin (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Storage (Re-Reg)
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1956	1931
4	Year Last Unit was Installed	1956	1958
5	Total installed cap (Gen name plate Rating in MW)	38.50	136.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	33	145
7	Plant Hours Connect to Load	8,639	8,710
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	39	151
10	(b) Under the Most Adverse Oper Conditions	39	151
11	Average Number of Employees	1	1
12	Net Generation, Exclusive of Plant Use - Kwh	136,640,000	398,837,000
13	Cost of Plant		
14	Land and Land Rights	0	1,086,564
15	Structures and Improvements	5,243,965	105,316,429
16	Reservoirs, Dams, and Waterways	31,435,214	29,886,552
17	Equipment Costs	11,835,096	17,827,191
18	Roads, Railroads, and Bridges	1,952,391	3,870,462
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	50,466,666	157,987,198
21	Cost per KW of Installed Capacity (line 20 / 5)	1,310.8225	1,161.6706
22	Production Expenses		
23	Operation Supervision and Engineering	41,223	1,439,615
24	Water for Power	2,071	25,319
25	Hydraulic Expenses	103,163	755,695
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	646,118	666,372
28	Rents	158,170	104,941
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	50,129	54,828
31	Maintenance of Reservoirs, Dams, and Waterways	30,915	61,562
32	Maintenance of Electric Plant	12,746	129,734
33	Maintenance of Misc Hydraulic Plant	135,462	328,074
34	Total Production Expenses (total 23 thru 33)	1,179,997	3,566,140
35	Expenses per net KWh	0.0086	0.0089

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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 Plant Name: Toketee (d)	FERC Licensed Project No. 20 Plant Name: Oneida (e)	FERC Licensed Project No. 2630 Plant Name: Prospect No. 2 (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
43	14	36	6
8,650	8,760	8,759	7
			8
45	28	36	9
45	28	36	10
1	2	1	11
183,992,000	28,864,000	166,763,000	12
			13
0	36,698	105,168	14
4,069,708	1,893,739	3,530,192	15
12,752,241	6,316,949	30,634,026	16
4,417,196	6,316,113	7,058,298	17
264,441	503,332	325,069	18
0	0	0	19
21,503,586	15,066,831	41,652,753	20
505.9667	502.2277	1,301.6485	21
			22
69,365	97,816	344,111	23
2,287	0	11,334	24
113,881	32,579	2,838	25
0	0	0	26
838,974	803,125	636,432	27
174,603	10,797	53,201	28
0	0	265	29
59,235	10,323	45,406	30
11,074	1,901	166,156	31
109,519	74,454	33,615	32
148,326	34,440	204,619	33
1,527,264	1,065,435	1,497,977	34
0.0083	0.0369	0.0090	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 1927 Plant Name: Slide Creek (b)	FERC Licensed Project No. 20 Plant Name: Soda (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1951	1924
4	Year Last Unit was Installed	1951	1924
5	Total installed cap (Gen name plate Rating in MW)	18.00	14.45
6	Net Peak Demand on Plant-Megawatts (60 minutes)	17	6
7	Plant Hours Connect to Load	8,237	5,124
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	44,735,000	14,474,000
13	Cost of Plant		
14	Land and Land Rights	0	511,083
15	Structures and Improvements	2,185,789	732,396
16	Reservoirs, Dams, and Waterways	14,878,343	10,532,263
17	Equipment Costs	8,964,422	5,424,548
18	Roads, Railroads, and Bridges	463,083	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	26,491,637	17,200,290
21	Cost per KW of Installed Capacity (line 20 / 5)	1,471.7576	1,190.3315
22	Production Expenses		
23	Operation Supervision and Engineering	38,542	45,979
24	Water for Power	968	0
25	Hydraulic Expenses	48,232	15,204
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	334,037	493,654
28	Rents	73,949	5,115
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	58,050	8,849
31	Maintenance of Reservoirs, Dams, and Waterways	9,060	92
32	Maintenance of Electric Plant	65,515	32,749
33	Maintenance of Misc Hydraulic Plant	74,266	16,072
34	Total Production Expenses (total 23 thru 33)	702,619	617,714
35	Expenses per net KWh	0.0157	0.0427

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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 Plant Name: Soda Springs (d)	FERC Licensed Project No. 2111 Plant Name: Swift No. 1 (e)	FERC Licensed Project No. 2071 Plant Name: Yale (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	254	167	6
8,062	5,462	5,782	7
			8
12	264	164	9
12	264	164	10
2	1	1	11
34,278,000	583,525,000	482,067,000	12
			13
0	14,160,894	8,363,013	14
4,226,017	71,309,098	16,121,571	15
89,359,648	46,964,944	30,362,737	16
2,633,367	24,634,936	16,631,223	17
2,088,444	1,133,091	2,051,638	18
0	0	0	19
98,307,476	158,202,963	73,530,182	20
8,937.0433	659.1790	548.7327	21
			22
13,181	2,495,852	1,445,241	23
592	44,680	24,946	24
400,872	1,556,708	744,583	25
0	0	0	26
418,717	678,442	570,766	27
45,191	185,191	103,398	28
0	0	0	29
31,580	30,657	29,123	30
217,095	57,937	49,773	31
101,320	149,641	115,930	32
39,880	547,838	325,716	33
1,268,428	5,746,946	3,409,476	34
0.0370	0.0098	0.0071	35

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: Olmsted (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	
2	Plant Construction type (Conventional or Outdoor)	Conventional	
3	Year Originally Constructed	1904	
4	Year Last Unit was Installed	1922	
5	Total installed cap (Gen name plate Rating in MW)	10.30	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	6	0
7	Plant Hours Connect to Load	3,336	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	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	6,475,000	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	32,120	0
24	Water for Power	0	0
25	Hydraulic Expenses	31,289	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	274,249	0
28	Rents	3,758	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	47,185	0
31	Maintenance of Reservoirs, Dams, and Waterways	4,129	0
32	Maintenance of Electric Plant	483	0
33	Maintenance of Misc Hydraulic Plant	81,844	0
34	Total Production Expenses (total 23 thru 33)	475,057	0
35	Expenses per net KWh	0.0734	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

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

Schedule Page: 406 Line No.: -1 Column: b

This footnote applies to all hydroelectric generating facilities with current generation. All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 406 Line No.: 1 Column: b

Copco No. 1
Pondage for peaking - storage, Upper Klamath Lake

Schedule Page: 406 Line No.: 1 Column: d

Clearwater No. 1
Forebay for peaking

Schedule Page: 406 Line No.: 1 Column: e

Clearwater No. 2
Forebay for peaking

Schedule Page: 406.1 Line No.: 1 Column: b

Fish Creek
Forebay for peaking

Schedule Page: 406.1 Line No.: 1 Column: d

Iron Gate
Storage for regulation

Schedule Page: 406.1 Line No.: 1 Column: e

JC Boyle
Pondage for peaking - storage, Upper Klamath Lake

Schedule Page: 406.1 Line No.: 1 Column: f

Lemolo No. 1
Storage, Lemolo Lake

Schedule Page: 406.2 Line No.: 1 Column: b

Lemolo No. 2
Storage, Lemolo Lake

Schedule Page: 406.2 Line No.: 1 Column: d

Toketee
Pondage for peaking - storage, Lemolo Lake

Schedule Page: 406.2 Line No.: 1 Column: f

Prospect No. 2
Forebay for peaking

Schedule Page: 406.4 Line No.: -1 Column: b

Olmsted
The Olmsted plant is owned by the U.S. Bureau of Land Reclamation. PacifiCorp had a 25-year lease agreement that ended in 2015 to operate and take all the generation. In September 2015, the Olmsted Plant was retired when the U.S. Department of Interior decided to replace the Olmsted Plant with a new hydroelectric facility in the same vicinity.

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	6.70	6.4	29,969,000	33,475,897
3	Bend	1913	1.11	1.0	2,396,000	1,578,623
4	Big Fork 2652	1910	4.15	4.6	26,515,000	7,599,319
5	Eagle Point	1957	2.81	2.8	16,857,000	1,934,235
6	East Side 2082	1924	3.20	1.0	2,000	1,991,695
7	Fall Creek 2082	1903	2.20	2.0	9,699,000	1,434,427
8	Fountain Green	1922	0.16			
9	Granite	1896	2.00	1.2	5,516,000	5,237,483
10	Gunlock	1917	0.75	0.4	772,000	683,045
11	Last Chance	1983	1.73	0.8	1,929,000	2,805,024
12	Paris	1910	0.72	0.1	2,441,000	449,804
13	Pioneer 2722	1897	5.00	3.4	9,846,000	11,380,608
14	Prospect No. 1 2630	1912	3.76	4.6	6,378,000	2,590,660
15	Prospect No. 3 2337	1932	7.20	7.7	27,781,000	8,823,320
16	Prospect No. 4 2630	1944	1.00	0.9	1,219,000	2,409,792
17	Sand Cove	1926	0.80	0.3	543,000	933,152
18	Stairs 597	1895	1.00	1.2	3,897,000	1,721,738
19	Veyo	1920	0.50	0.2	219,000	893,252
20	Viva Naughton	1986	0.74	0.3	1,005,000	1,232,115
21	Wallowa Falls 308	1921	1.10	1.0	3,490,000	3,220,805
22	Weber 1744	1911	3.85	2.0	9,926,000	3,638,500
23	West Side 2082	1908	0.60	0.6	-21,000	468,574
24	Keno Regulating Dam 2082					7,527,522
25	Upper Klamath Lake 2082					3,847,268
26	North Umpqua 1927					15,480,603
27						
28	Pumping Plant:					
29	Lifton	1917	-2.80	-3.0	-2,776,000	19,497,516
30						
31	Wind:					
32	Dunlap Ranch 1	2010	111.00	111.0	339,706,000	240,938,386
33	Foote Creek	1999	32.15	32.6	81,453,000	38,474,134
34	Glenrock	2008	99.00	99.0	289,386,000	202,236,414
35	Glenrock III	2009	39.00	39.0	108,844,000	87,955,208
36	Rolling Hills	2009	99.00	99.0	261,284,000	203,986,026
37	Goodnoe Hills	2008	94.00	94.0	186,746,000	185,577,179
38	Leaning Juniper 1	2006	100.00	100.5	188,567,000	178,550,177
39	Marengo	2007	140.40	140.4	298,771,000	240,969,143
40	Marengo II	2008	70.20	70.2	137,848,000	129,806,443
41	Seven Mile Hill	2008	99.00	99.0	296,563,000	201,814,421
42	Seven Mile Hill II	2008	19.50	19.5	64,063,000	42,416,334
43	High Plains	2009	99.00	99.0	250,864,000	220,314,919
44	McFadden Ridge I	2009	28.50	28.5	78,271,000	56,998,530
45						
46	Solar:					

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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
4,996,403	481,644		115,703	Water		2
1,422,183	149,990		5,180	Water		3
1,831,161	353,290		124,971	Water		4
688,340	269,271		109,046	Water		5
622,405	104,657		104,823	Water		6
652,012	140,680		38,165	Water		7
				Water		8
2,618,742	187,487		34,177	Water		9
910,727	70,522		20,811	Water		10
1,621,401	116,375		5,360	Water		11
624,728	57,645		25,603	Water		12
2,276,122	544,871		124,185	Water		13
689,005	147,766		46,686	Water		14
1,225,461	346,785		299,957	Water		15
2,409,792	48,524		12,222	Water		16
1,166,440	86,787		58,326	Water		17
1,721,738	154,740		18,206	Water		18
1,786,504	78,359		87,544	Water		19
1,665,020	180,063		95,081	Water		20
2,928,005	97,524		3,660	Water		21
945,065	277,627		11,921	Water		22
780,957	4,477		2,655	Water		23
	52,169		3,787			24
	293,332		24,661			25
						26
						27
						28
-6,963,399	250,793		36,804	Water		29
						30
						31
2,170,616	319,675		1,385,883	Wind		32
1,196,707	162,598		1,648,045	Wind		33
2,042,792	601,778		1,308,106	Wind		34
2,255,262	210,345		517,762	Wind		35
2,060,465	594,395		1,278,667	Wind		36
1,974,225	949,229		2,300,670	Wind		37
1,785,502	1,269,677		1,284,021	Wind		38
1,716,304	1,282,960		1,278,094	Wind		39
1,849,095	569,870		630,893	Wind		40
2,038,530	615,757		1,350,189	Wind		41
2,175,197	136,646		272,765	Wind		42
2,225,403	825,307		1,844,714	Wind		43
1,999,948	231,636		423,681	Wind		44
						45
						46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	Black Cap	2012	2.00	2.0	4,469,000	74,986
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Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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.
37,493	506,332			Solar		1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
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						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.

This footnote applies to all hydroelectric generating facilities with current generation. All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 410 Line No.: 6 Column: a

East Side

The East Side plant was significantly curtailed pursuant to Section 6.2 of the Klamath Hydroelectric Settlement Agreement in FERC Docket No. P-2082-000.

Schedule Page: 410 Line No.: 8 Column: a

Fountain Green

The Fountain Green hydroelectric generating facility was sold in March 2015 to the Utah Division of Wildlife Resources. For more information, refer to Item 3 in Important Changes During the Year in this Form No. 1.

Schedule Page: 410 Line No.: 23 Column: a

West Side

The West Side plant generation supplies station use and was significantly curtailed pursuant to Section 6.2 of the Klamath Hydroelectric Settlement Agreement in FERC Docket No. P-2082-000.

Schedule Page: 410 Line No.: 24 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.: 25 Column: a

Upper Klamath Lake

Storage reservoir for six plants on the Klamath River (Copco No. 1, Copco No. 2, East Side, West Side, JC Boyle and Iron Gate).

Schedule Page: 410 Line No.: 26 Column: a

North Umpqua

Represents facilities that support the North Umpqua River system projects. All common roads, employee houses, control equipment, etc. are in this account.

Schedule Page: 410 Line No.: 29 Column: a

Lifton

Used in regulating the release of water from Bear Lake and in maintaining proper water surface level in the Bear River near St. Charles, Idaho.

Schedule Page: 410 Line No.: 31 Column: a

Common costs for the operation of these facilities are allocated to each plant based upon the unit's name plate rating.

This footnote applies to all wind-powered generating facilities with current generation. All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 410 Line No.: 33 Column: a

Foote Creek

The Foote Creek wind-powered generating facility is operated by PacifiCorp (previously operated by SeaWest Energy) and is jointly owned by PacifiCorp and Eugene Water and Electric Board with an undivided interest of 78.79% and 21.21%, respectively. Data reported in line 33 represents PacifiCorp's share.

Schedule Page: 410.1 Line No.: 1 Column: a

Black Cap

PacifiCorp has an agreement with Citizens Asset Finance, Inc. to lease the Black Cap Solar generating facility. The lease has a 16-year term from October 2012 to October 2028 and is accounted for as an operating lease.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	PG&E ROUND MTN, CA	500.00	500.00	Steel Tower	47.00		1
2	DIXONVILLE, OR	MERIDIAN, OR	500.00	500.00	Steel Tower	74.00		1
3	CAPTAIN JACK, OR	MALIN, OR	500.00	500.00	Steel Tower	7.00		1
4	KLAMATH CO-GEN, OR	CAPTAIN JACK, OR	500.00	500.00	Steel Tower	26.00		1
5	MERIDIAN, OR	KLAMATH CO-GEN, OR	500.00	500.00	Steel Tower	58.00		1
6	ALVEY, OR	DIXONVILLE, OR	500.00	500.00	Steel Tower	58.00		1
7	MIDPOINT, ID	MALIN, OR	500.00	500.00	Steel Tower	447.00		1
8	COLSTRIP 4, MT	SWITCHYARD, MT	500.00	500.00	Steel Tower	1.00		1
9	COLSTRIP, MT	BROADVIEW A, MT	500.00	500.00	Steel Tower	112.00		1
10	COLSTRIP, MT	BROADVIEW B, MT	500.00	500.00	Steel Tower	116.00		1
11	BROADVIEW, MT	TOWNSEND A, MT	500.00	500.00	Steel Tower	133.00		1
12	BROADVIEW, MT	TOWNSEND B, MT	500.00	500.00	Steel Tower	133.00		1
13	500 kV costs and expenses							
14								
15	Subtotal 500 kV					1,212.00		12
16								
17	90TH SOUTH, UT	CAMP WILLIAMS #3, UT	345.00	345.00	Steel - SP	11.00		1
18	90TH SOUTH, UT	CAMP WILLIAMS #4, UT	345.00	345.00			11.00	1
19	90TH SOUTH, UT	CAMP WILLIAMS #1, UT	345.00	345.00	Steel - SP	11.00		1
20	90TH SOUTH, UT	TERMINAL, UT	345.00	345.00			16.00	1
21	TERMINAL, UT	CAMP WILLIAMS #2, UT	345.00	345.00	Steel - SP	15.00	11.00	1
22	TERMINAL, UT	BORAH, ID	345.00	345.00	Wood - H	138.00		1
23	TERMINAL, UT	BORAH, ID	345.00	345.00	Steel - SP		47.00	1
24	BEN LOMOND, UT	POPULUS #1, ID	345.00	345.00			82.00	1
25	BEN LOMOND, UT	POPULUS #2, ID	345.00	345.00	Steel - SP	86.00		1
26	BEN LOMOND, UT	CAMP WILLIAMS, UT	345.00	345.00	Steel - SP	69.00		1
27	BEN LOMOND, UT	TERMINAL, UT	345.00	345.00		47.00		1
28	BEN LOMOND, UT	TERMINAL, UT	345.00	345.00	Steel - SP		47.00	1
29	CAMP WILLIAMS, UT	MONA #3, UT	345.00	345.00	Wood - H	47.00		1
30	CAMP WILLIAMS, UT	MONA #1, UT	345.00	345.00	Wood - H	47.00		1
31	CAMP WILLIAMS, UT	MONA #2, UT	345.00	345.00	Steel Tower	47.00		1
32	CAMP WILLIAMS, UT	MONA #4, UT	345.00	345.00		5.00	42.00	1
33	CURRANT CREEK, UT	MONA, UT	345.00	345.00	Steel - SP	1.00		1
34	EMERY, UT	CAMP WILLIAMS, UT	345.00	345.00	Steel Tower	121.00		1
35	EMERY, UT	HUNTINGTON, UT	345.00	345.00	Wood - H	20.00		1
36					TOTAL	16,969.00	715.00	282

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.
3-1852 ACSR 51/27								1
3-1272 ACSR 36/1								2
3-1272 ACSR 36/1								3
3-1272 ACSR 54/19								4
3-1272 ACSR 54/19								5
3-2250 AAC /91								6
3-1272 ACSR 36/1								7
795 KCM ACSR								8
795 KCM ACSR								9
795 KCM ACSR								10
795 KCM ACSR								11
795 KCM ACSR								12
	13,339,699	266,393,077	279,732,776	4,569	390,433	362,482	757,484	13
								14
	13,339,699	266,393,077	279,732,776	4,569	390,433	362,482	757,484	15
								16
								17
								18
1272 ACSR 45/7								19
1272 ACSR 45/7								20
1272 ACSR 45/7								21
954 ACSR 45/7								22
1272 ACSR 45/7								23
1272 ACSR 45/7								24
1272 ACSR 45/7								25
1272 ACSR 45/7								26
1272 ACSR 45/7								27
1272 ACSR 45/7								28
954 ACSR 45/7								29
1272 ACSR 45/7								30
954 ACSR 45/7								31
954 ACSR 45/7								32
954 ACSR 54/7								33
1272 ACSR 45/7								34
954 ACSR 45/7								35
	229,153,883	3,385,069,822	3,614,223,705	409,509	17,142,995	2,248,767	19,801,271	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	/ /	End of 2015/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.
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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
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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	EMERY, UT	SIGURD #1, UT	345.00	345.00	Steel - H	74.00		1
2	EMERY, UT	SIGURD #2, UT	345.00	345.00	Steel - H	75.00		1
3	FOUR CORNERS, NM	PINTO, UT	345.00	345.00	Wood - H	100.00		1
4	GOSHEN, ID	KINPORT, ID	345.00	345.00	Wood - H	41.00		1
5	HUNTINGTON, UT	HUNT PLANT 1, UT	345.00	345.00	Steel Tower	1.00		1
6	HUNTINGTON, UT	HUNT PLANT 2, UT	345.00	345.00	Steel Tower	1.00		1
7	HUNTINGTON, UT	PINTO, UT	345.00	345.00	Steel - SP	158.00		1
8	HUNTINGTON, UT	SPANISH FORK, UT	345.00	345.00	Steel Tower	78.00		1
9	JIM BRIDGER, WY	BORAH, ID	345.00	345.00	Steel Tower	240.00		1
10	JIM BRIDGER, WY	KINPORT, ID	345.00	345.00	Steel - SP	234.00		1
11	MONA, UT	SIGURD #1, UT	345.00	345.00	Wood - H	69.00		1
12	MONA, UT	SIGURD #2, UT	345.00	345.00	Steel - SP		69.00	1
13	MONA, UT	HUNTINGTON, UT	345.00	345.00	Steel - SP	60.00		1
14	SIGURD, UT	UT/NV STATE LINE	345.00	345.00	Steel Tower	190.00		1
15	SPANISH FORK, UT	CAMP WILLIAMS, UT	345.00	345.00			35.00	1
16	TERMINAL, UT	CAMP WILLIAMS, UT	345.00	345.00			23.00	1
17	CLOVER, UT	OQUIRRH, UT	345.00	345.00	Steel Tower	100.00		1
18	RED BUTTE, UT	SIGURD, UT	345.00	345.00	Steel - H	170.00		1
19	JIM BRIDGER, WY	GOSHEN, ID	345.00	345.00	Steel Tower	226.00		1
20	BORAH, ID	MIDPOINT #1, ID	345.00	345.00	Wood - H	79.00		1
21	BORAH, ID	MIDPOINT #2, ID	345.00	345.00	Wood - H	78.00		1
22	KINPORT, ID	MIDPOINT, ID	345.00	345.00	Steel - SP	113.00		1
23	345kV costs and expenses							
24								
25	Subtotal 345 kV					2,752.00	383.00	41
26								
27	ALVEY, OR	DIXONVILLE, OR	230.00	230.00	Wood - H	59.00		1
28	ANTELOPE, ID	ANACONDA, MT	230.00	230.00	Wood - H	76.00		1
29	ANTELOPE, ID	LOST RIVER, ID	230.00	230.00	Wood - H	20.00		1
30	ATLANTIC CITY, WY	COLUMBIA GENEVA, WY	230.00	230.00	Wood - H	1.00		1
31	BEN LOMOND, UT	NAUGHTON #1, WY	230.00	230.00	Wood - H	88.00		1
32	BEN LOMOND, UT	NAUGHTON #2, WY	230.00	230.00	Wood - H	88.00		1
33	BIRCH CREEK, UT	RAILROAD, WY	230.00	230.00	Wood - H	19.00		1
34	BITTER CREEK, WY	MONELL, WY	230.00	230.00	Wood - H	3.00		1
35	BRIDGER PUMP, WY	MANS FACE, WY	230.00	230.00	Wood - H	1.00		1
36					TOTAL	16,969.00	715.00	282

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

TRANSMISSION LINE STATISTICS (Continued)

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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
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)	
954 ACSR 45/7								1
954 ACSR 54/7								2
795 ACSR 45/7								3
795 ACSR 26/7								4
2156 ACSR 8419								5
2156 ACSR 8419								6
795 ACSR 45/7								7
1272 ACSR 45/7								8
1272 ACSR 36/1								9
1272 ACSR 36/1								10
795 ACSR 45/7								11
954 ACSR 45/7								12
954 ACSR 54/7								13
954 ACSR 54/7								14
1272 ACSR 45/7								15
1272 ACSR 45/7								16
1949 ACSR 45/7								17
2-954 ACSR 45/7								18
2-1272 ACSR 36/1								19
3-1272 ACSR 45/7								20
3-1272 ACSR 45/7								21
2-1272 ACSR 45/7								22
	150,688,937	1,626,046,639	1,776,735,576	3,099	1,684,607	468,377	2,156,083	23
								24
	150,688,937	1,626,046,639	1,776,735,576	3,099	1,684,607	468,377	2,156,083	25
								26
1272 ACSR 36/1								27
1272 ACSR 45/7								28
795 ACSR 45/7								29
1272 ACSR 36/1								30
795 ACSR 26/7								31
795 ACSR 26/7								32
954 ACSR 54/7								33
795 ACSR 26/7								34
1272 ACSR 36/1								35
	229,153,883	3,385,069,822	3,614,223,705	409,509	17,142,995	2,248,767	19,801,271	36

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TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	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	BUFFALO, WY	CASPER, WY	230.00	230.00	Wood - H	107.00		1
2	CASPER, WY	DAVE JOHNSTON, WY	230.00	230.00	Wood - H	36.00		1
3	CASPER, WY	RIVERTON, WY	230.00	230.00	Wood - H	110.00		1
4	CHAPPEL CREEK, WY	CRAVEN CREEK, WY	230.00	230.00	Steel - SP	30.00		1
5	CHAPPEL CREEK, WY	JONAH GAS, WY	230.00	230.00	Wood - H	32.00		1
6	CHAPPEL CREEK, WY	RILEY RIDGE, WY	230.00	230.00	Wood - H	29.00	6.00	1
7	CRAVEN CREEK, WY	PIONEER, WY	230.00	230.00	Wood - H	2.00		1
8	DAVE JOHNSTON, WY	SPENCE, WY	230.00	230.00	Wood - H	31.00		1
9	DAVE JOHNSTON, WY	WYODAK, WY	230.00	230.00	Wood - H	69.00		1
10	DIXONVILLE 500kV, OR	DIXONVILLE 230kV, OR	230.00	230.00	Wood - H	1.00		1
11	DIXONVILLE, OR	RESTON (BPA), OR	230.00	230.00	Wood - H	17.00		1
12	FAIRVIEW (BPA), OR	ISTHMUS, OR	230.00	230.00	Wood - H	12.00		1
13	FIREHOLE, WY	MONUMENT, WY	230.00	230.00	Wood - H	49.00		1
14	FRY, OR	BETHEL, OR	230.00	230.00	Wood - H	26.00		1
15	FRY, OR	ALVEY, OR	230.00	230.00	Wood - H	45.00		1
16	GLEN CANYON, AZ	SIGURD, UT	230.00	230.00	Wood - H	159.00		1
17	GONDER, UT - NV STATE	PAVANT, UT	230.00	230.00	Wood - H	98.00		1
18	BUFFALO, WY	SHERIDAN (MDU), WY	230.00	230.00	Wood - H	40.00		1
19	DIXONVILLE, OR	GRANTS PASS, OR	230.00	230.00	Wood - H	62.00		1
20	HURRICANE, OR	WALLA WALLA, WA	230.00	230.00	Wood - H	78.00		1
21	POINT OF ROCKS, WY	DAVE JOHNSTON, WY	230.00	230.00	Wood - H	209.00		1
22	JIM BRIDGER, WY	SPENCE, WY	230.00	230.00	Wood - H	149.00		1
23	KLAMATH FALLS, OR	MALIN, OR	230.00	230.00	Wood - H	35.00		1
24	LIMA, WY	ROBERSON, WY	230.00	230.00	Wood - H	2.00		1
25	LONE PINE, OR	KLAMATH FALLS, OR	230.00	230.00	Wood - H	76.00		1
26	LONE PINE, OR	MERIDIAN #1, OR	230.00	230.00	Steel - SP	5.00		1
27	LONE PINE, OR	MERIDIAN #2, OR	230.00	230.00	Steel - SP	5.00		1
28	MCNARY (BPA), WA	WALLA WALLA, WA	230.00	230.00	Wood - H	56.00		1
29	MERIDIAN, OR	GRANTS PASS, OR	230.00	230.00	Wood - H	35.00		1
30	HIGH PLAINS, WY	STANDPIPE, WY	230.00	230.00	Wood - H	38.00		1
31	MONUMENT, WY	EXXON, WY	230.00	230.00	Wood - H	13.00		1
32	MONUMENT, WY	CRAVEN CREEK, WY	230.00	230.00	Wood - H	20.00		1
33	NAUGHTON, WY	TREASURETON, ID	230.00	230.00	Wood - H	80.00		1
34	NAUGHTON, WY	MONUMENT, WY	230.00	230.00	Wood - H	30.00		1
35	NAUGHTON, WY	CRAVEN CREEK, WY	230.00	230.00	Wood - H	16.00		1
36					TOTAL	16,969.00	715.00	282

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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
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 ACSR 36/1								1
								2
1272 ACSR 36/1								3
954 ACSR 54/7								4
1272 ACSR 45/7								5
1272 ACSR 45/7								6
1272 ACSR 45/7								7
1272 ACSR 45/7								8
1272 ACSR 36/1								9
1272 ACSR 36/1								10
795 ACSR 26/7								11
1272 ACSR 36/1								12
1272 ACSR 45/7								13
1272 ACSR 36/1								14
1272 ACSR 36/1								15
954 ACSR 45/7								16
795 ACSR 45/7								17
795 ACSR 26/7								18
1272 ACSR 36/1								19
1272 ACSR 36/1								20
1272 ACSR 36/1								21
1272 ACSR 36/1								22
1272 ACSR 36/1								23
1272 ACSR 45/7								24
795 ACSR 26/7								25
1272 ACSR 54/19								26
1272 ACSR 36/1								27
1272 ACSR 36/1								28
1272 ACSR 36/1								29
1272 ACSR 45/7								30
1272 ACSR 36/1								31
1272 ACSR 45/7								32
1272 ACSR 45/7								33
1272 ACSR 36/1								34
954 ACSR 54/7								35
	229,153,883	3,385,069,822	3,614,223,705	409,509	17,142,995	2,248,767	19,801,271	36

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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	PALISADES SS, WY	BLUE RIM, WY	230.00	230.00	Wood - H	4.00		1
2	PAROWAN VALLEY, UT	SIGURD, UT	230.00	230.00	Wood - H	94.00		1
3	PAROWAN VALLEY, UT	WEST CEDAR, UT	230.00	230.00	Wood - H	26.00		1
4	PAVANT, UT	SIGURD, UT	230.00	230.00	Wood - H	43.00		1
5	JIM BRIDGER, WY	ROCK SPRINGS, WY	230.00	230.00	Wood - H	35.00		1
6	POMONA, WA	UNION GAP, WA	230.00	230.00	Wood - H	8.00		1
7	RIVERTON, WY	ROCK SPRINGS, WY	230.00	230.00	Wood - H	118.00		1
8	RIVERTON, WY	THERMOPOLIS, WY	230.00	230.00	Wood - H	51.00		1
9	ROCK SPRINGS, WY	FLAMING GORGE, UT	230.00	230.00	Wood - H	55.00		1
10	ROCK SPRINGS, WY	JIM BRIDGER, WY	230.00	230.00	Wood - H	35.00		1
11	ROCK SPRINGS, WY	MONUMENT, WY	230.00	230.00	Wood - H	41.00		1
12	SHIRLEY BASIN, WY	DUNLAP RANCH, WY	230.00	230.00	Wood - H	12.00		1
13	SWIFT No. 1, WA	SWIFT No. 2, WA	230.00	230.00	Wood - H	2.00		1
14	SWIFT No. 2, WA	WOODLAND (BPA) SS, WA	230.00	230.00	Wood - H	23.00		1
15	TALBOT, WA	MARENGO II, WA	230.00	230.00	Wood - H	7.00		1
16	TAP TO HANNA, OR	NICKEL MOUNTAIN, OR	230.00	230.00	Wood - H	9.00		1
17	THERMOPOLIS, WY	YELLOWTAIL, MT	230.00	230.00	Wood - H	176.00		1
18	TREASURETON, ID	BRADY, ID	230.00	230.00	Wood - H	66.00		1
19	TROUTDALE (BPA), OR	GRESHAM (PGE), OR	230.00	230.00	Steel Tower	6.00		1
20	TROUTDALE (BPA), OR	LINNEMAN (PGE), OR	230.00	230.00			7.00	1
21	UNION GAP, WA	MIDWAY (BPA), WA	230.00	230.00	Wood - H	39.00		1
22	WALLA WALLA, WA	LEWISTON (AVISTA), ID	230.00	230.00	Wood - H	45.00		1
23	WALLA WALLA, WA	WANAPUM (GPUD), WA	230.00	230.00	Wood - H	33.00		1
24	WANAPUM (GPUD), WA	POMONA, WA	230.00	230.00	Wood - H	37.00		1
25	WINDSTAR, WY	GLENROCK, WY	230.00	230.00	Wood - H	13.00		1
26	WYODAK, WY	BUFFALO, WY	230.00	230.00	Wood - H	69.00		1
27	YAMSAY (BPA), OR	KLAMATH FALLS, OR	230.00	230.00	Wood - H	63.00		1
28	SHERIDAN (MDU), WY	YELLOWTAIL, MT	230.00	230.00	Wood - H	62.00		1
29	230kV costs and expenses							
30								
31	Subtotal 230 kV					3,329.00	13.00	72
32								
33	BIG GRASSY, ID	JEFFERSON, ID	161.00	161.00	Wood - H		82.00	1
34	ANTELOPE, ID	GOSHEN, ID	161.00	161.00	Wood - H	45.00		1
35	BONNEVILLE, ID	EAGLEROCK, ID	161.00	161.00	Wood - SP	9.00		1
36					TOTAL	16,969.00	715.00	282

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 ACSR 36/1								1
795 ACSR 45/7								2
795 ACSR 45/7								3
795 ACSR 45/7								4
1272 ACSR 45/7								5
1272 ACSR 36/1								6
1272 ACSR 36/1								7
1272 ACSR 36/1								8
1272 ACSR 36/1								9
1272 ACSR 36/1								10
1272 ACSR 36/1								11
795 ACSR 26/7								12
954 ACSR 45/7								13
954 ACSR 45/7								14
795 ACSR 26/7								15
795 ACSR 26/7								16
1272 ACSR 36/1								17
795 ACSR 26/7								18
954 ACSR 45/7								19
900 ACSR 54/7								20
954 ACSR 45/7								21
1272 ACSR 36/1								22
1272 ACSR 36/1								23
1272 ACSR 36/1								24
1272 ACSR 45/7								25
1272 ACSR 36/1								26
795 ACSR 26/7								27
795 ACSR 26/7								28
	18,995,587	388,558,750	407,554,337	66,020	3,653,604	520,222	4,239,846	29
								30
	18,995,587	388,558,750	407,554,337	66,020	3,653,604	520,222	4,239,846	31
								32
250I CU /18								33
397.5 ACSR 26/7								34
954 ACSR 45/7								35
	229,153,883	3,385,069,822	3,614,223,705	409,509	17,142,995	2,248,767	19,801,271	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	/ /	End of 2015/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.
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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	GOSHEN, ID	GRACE, ID	161.00	161.00	Wood - H	57.00		1
2	GOSHEN, ID	RIGBY, ID	161.00	161.00	Wood - H	31.00		1
3	GOSHEN, ID	SUGARMILL, ID	161.00	161.00	Wood - SP	17.00		1
4	SUGARMILL, ID	RIGBY, ID	161.00	161.00	Wood - SP	17.00		1
5	EAGLEROCK, ID	GOSHEN, ID	161.00	161.00	Wood - H	15.00		1
6	YELLOWTAIL, MT	RIMROCK, MT	161.00	161.00	Wood - H	46.00		1
7	RIGBY, ID	JEFFERSON, ID	161.00	161.00	Wood - SP	18.00		1
8	GOSHEN, ID	JEFFERSON, ID	161.00	161.00	Wood - H		30.00	1
9	161kV costs and expenses							
10								
11	Subtotal 161 kV					255.00	112.00	11
12								
13	90TH SOUTH, UT	SANDY, UT	138.00	138.00	Steel - SP	1.00		1
14	90TH SOUTH, UT	DUMAS #1, UT	138.00	138.00	Wood - H	12.00		1
15	90TH SOUTH, UT	DUMAS #2, UT	138.00	138.00	Wood - H	6.00		1
16	90TH SOUTH, UT	OQUIRRH, UT	138.00	138.00	Wood - SP	10.00		1
17	ABAJO, UT	PINTO, UT	138.00	138.00	Wood - H	44.00		1
18	AGRIUM, UT	THREEMILE KNOLL, ID	138.00	138.00	Wood - H	4.00		1
19	ANSCHTZ CO-GEN, WY	EVANSTON, WY	138.00	138.00	Wood - H	22.00		1
20	ANTELOPE, ID	SCOVILLE #1, ID	138.00	138.00	Wood - H	1.00		1
21	ANTELOPE, ID	SCOVILLE #2, ID	138.00	138.00	Wood - H	1.00		1
22	ASHGROVE, UT	CLOVER, UT	138.00	138.00	Wood - H	26.00		1
23	ASHLEY, UT	CARBON, UT	138.00	138.00	Wood - H	102.00		1
24	ASHLEY, UT	VERNAL, UT	138.00	138.00	Wood - H	12.00		1
25	BANGERTER, UT	OQUIRRH, UT	138.00	138.00	Wood - H		6.00	1
26	BDO, UT	BDO TAP, UT	138.00	138.00	Wood - SP	1.00		1
27	BEN LOMOND, UT	BRIGHAM CITY, UT	138.00	138.00	Wood - H	14.00		1
28	BEN LOMOND #1, UT	EL MONTE, UT	138.00	138.00	Steel - SP	14.00		1
29	BEN LOMOND #2, UT	EL MONTE, UT	138.00	138.00			13.00	1
30	BEN LOMOND, UT	HONEYVILLE, UT	138.00	138.00	Steel Tower	22.00		1
31	BEN LOMOND, UT	SYRACUSE #1, UT	138.00	230.00	Steel Tower	7.00	13.00	1
32	BEN LOMOND, UT	ANGLE, UT	138.00	138.00	Steel - SP	28.00		1
33	BEN LOMOND, UT	W ZIRCONIUM, UT	138.00	138.00	Wood - SP	14.00		1
34	BEN LOMOND, UT	WHEELON, UT	138.00	138.00	Steel Tower	42.00		1
35	BEN LOMOND, UT	SYRACUSE, UT	138.00	138.00	Steel Tower	25.00		1
36					TOTAL	16,969.00	715.00	282

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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)
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) 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.
250HH CU /7								1
397.5 ACSR 26/7								2
795 AAC /37								3
397.5 ACSR 26/7								4
1272 ACSR 45/7								5
556.5 ACSR 26/7								6
397.5 ACSR 26/7								7
250HH CU /7								8
	623,490	24,954,768	25,578,258		279,349	4,632	283,981	9
								10
	623,490	24,954,768	25,578,258		279,349	4,632	283,981	11
								12
795 AAC /37								13
795 AAC /37								14
795 AAC /37								15
795 ACSR 26/7								16
397.5 ACSR 26/7								17
397.5 ACSR 26/7								18
795 ACSR 26/7								19
397.5 ACSR 26/7								20
397.5 ACSR 26/7								21
397.5 ACSR 26/7								22
397.5 ACSR 26/7								23
397.5 ACSR 26/7								24
								25
397.5 ACSR 26/7								26
1272 ACSR 45/7								27
795 ACSR 45/7								28
795 ACSR 45/7								29
250 CUHD /12								30
795 AAC /37								31
397.5 ACSR 26/7								32
795 AAC /37								33
250 CUHD /12								34
1272 ACSR 45/7								35
	229,153,883	3,385,069,822	3,614,223,705	409,509	17,142,995	2,248,767	19,801,271	36

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

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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	BONANZA, UT	CHAPITA, UT	138.00	138.00	Wood - H	9.00		1
2	BRIDGERLAND, UT	GREEN CANYON, UT	138.00	138.00	Wood - SP	16.00		1
3	BRIGHAM CITY, UT	WHEELON, UT	138.00	138.00	Wood - H	24.00		1
4	BUTLERVILLE, UT	90TH SOUTH, UT	138.00	138.00	Steel - SP	9.00		1
5	CAMERON, UT	PAROWAN, UT	138.00	138.00	Wood - H	35.00		1
6	CAMERON, UT	SIGURD, UT	138.00	138.00	Wood - H	64.00		1
7	CANYON COMP, WY	STR 204, WY	138.00	138.00	Wood - H	12.00		1
8	CARBON, UT	HELPER #2, UT	138.00	138.00	Wood - H	2.00		1
9	CARBON, UT	SPANISH FORK #1, UT	138.00	138.00	Steel Tower	54.00		1
10	CARBON, UT	SPANISH FORK #2, UT	138.00	138.00	Steel Tower	52.00		1
11	CARBON, UT	MOAB, UT	138.00	138.00	Wood - H	120.00		1
12	CLEAR CREEK, WY	PAINTER, UT	138.00	138.00	Wood - SP	5.00		1
13	CLOVER, UT	NEBO, UT	138.00	138.00	Wood - SP	8.00		1
14	COLUMBIA, UT	SUNNYSIDE, UT	138.00	138.00	Wood - H	2.00		1
15	COTTONWOOD, UT	MCCLELLAND, UT	138.00	138.00	Steel - SP	6.00		1
16	COTTONWOOD, UT	HAMMER, UT	138.00	138.00	Wood - SP	5.00		1
17	COTTONWOOD, UT	SILVER CREEK, UT	138.00	138.00	Wood - SP	29.00		1
18	CUTLER, UT	WHEELON, UT	138.00	138.00	Wood - SP	1.00		1
19	DRY CREEK, UT	SPANISH FORK, UT	138.00	138.00	Steel - SP	5.00		1
20	DUMAS, UT	WESTFIELD, UT	138.00	138.00	Wood - SP	18.00		1
21	DYNAMO, UT	TRI-CITY #1, UT	138.00	138.00	Steel - SP	2.00		1
22	DYNAMO, UT	TRI-CITY #2, UT	138.00	138.00			3.00	1
23	EAST LAYTON, UT	105 TAP, UT	138.00	138.00	Steel - SP	15.00		1
24	EBAY TAP, UT	OQUIRRH, UT	138.00	138.00	Wood -SP	1.00		1
25	EL MONTE, UT	STR 30B , UT	138.00	138.00	Steel - SP	4.00		1
26	EL MONTE, UT	PIONEER, UT	138.00	138.00	Steel - SP	1.00		1
27	EVANSTON, WY	RAILROAD, UT	138.00	138.00	Wood - SP	3.00		1
28	FRANKLIN, ID	TREASURETON, ID	138.00	138.00	Wood - SP	10.00		1
29	FRANKLIN, ID	GREEN CANYON, UT	138.00	138.00	Wood - SP	25.00		1
30	GADSBY, UT	THIRD WEST, UT	138.00	138.00	Wood - SP	1.00		1
31	GADSBY, UT	TERMINAL, UT	138.00	138.00	Wood - SP	6.00		1
32	GADSBY, UT	JORDAN, UT	138.00	138.00	Wood - SP	1.00		1
33	GREEN CANYON, UT	NIBLEY, UT	138.00	138.00	Wood - SP	7.00		1
34	GREEN CANYON, UT	WHEELON, UT	138.00	138.00	Wood - SP	19.00		1
35	HALE, UT	MIDWAY, UT	138.00	138.00	Wood - H	19.00		1
36					TOTAL	16,969.00	715.00	282

TRANSMISSION LINE STATISTICS (Continued)

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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
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.
795 ACSR 26/7								1
1272 ACSR 45/7								2
795 ACSR 26/7								3
795 AAC /37								4
397.5 ACSR 26/7								5
397.5 ACSR 26/7								6
795 ACSR 26/7								7
556.5 ACSR 26/7								8
795 ACSR 26/7								9
1272 ACSR 45/7								10
954 ACSR 54/7								11
795 ACSR 26/7								12
1272 ACSR 45/7								13
397.5 ACSR 26/7								14
795 AAC /37								15
795 AAC /37								16
397.5 ACSR 26/7								17
250 CUHD /12								18
1272 ACSR 45/7								19
795 ACSR 26/7								20
795 ACSR 26/7								21
795 ACSR 26/7								22
795 ACSR 26/7								23
795 ACSR 26/7								24
1272 ACSR 45/7								25
1272 ACSR 45/7								26
795 ACSR 26/7								27
795 ACSR 26/7								28
397.5 ACSR 26/7								29
1272 AAC /61								30
1272 ACSR 45/7								31
1272 ACSR 45/7								32
1272 ACSR 45/7								33
397.5 ACSR 26/7								34
397.5 ACSR 26/7								35
	229,153,883	3,385,069,822	3,614,223,705	409,509	17,142,995	2,248,767	19,801,271	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	/ /	End of 2015/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	HALE, UT	TANNER, UT	138.00	138.00	Wood - H	7.00		1
2	HALE, UT	SPANISH FORK, UT	138.00	138.00	Wood - H	18.00		1
3	HAMMER, UT	BUTLERVILLE, UT	138.00	138.00			2.00	1
4	HONEYVILLE, UT	LAMPO, UT	138.00	138.00	Wood - H	25.00		1
5	HONEYVILLE, UT	WHEELON, UT	138.00	138.00			14.00	1
6	HUNTINGTON, UT	MCFADDEN, UT	138.00	138.00	Wood - H	7.00		1
7	JERUSALEM, UT	NEBO, UT	138.00	138.00	Wood - H	26.00		1
8	JORDAN, UT	THIRDWEST, UT	138.00	138.00	Wood - SP	1.00		1
9	JORDAN, UT	MCCLELLAND, UT	138.00	138.00	Wood - SP	5.00		1
10	JORDAN, UT	TERMINAL, UT	138.00	138.00	Wood - SP	6.00		1
11	BARNEYS, UT	GRINDING, UT	138.00	138.00	Wood - SP	1.00		1
12	KEARNS, UT	TAYLORSVILLE, UT	138.00	138.00	Wood - SP	3.00		1
13	KEARNS, UT	WEST VALLEY, UT	138.00	138.00	Wood - SP	2.00		1
14	LONE PEAK, UT	CAMP WILLIAMS, UT	138.00	138.00			8.00	1
15	MCCLELLAND, UT	MID VALLEY, UT	138.00	138.00	Wood - SP	6.00		1
16	MCFADDEN, UT	BLACKHAWK, UT	138.00	138.00	Wood - H	11.00		1
17	MID VALLEY, UT	TAYLORSVILLE, UT	138.00	138.00	Wood - SP	4.00	2.00	1
18	MID VALLEY #2, UT	COTTONWOOD, UT	138.00	138.00	Wood - SP	5.00		1
19	MID VALLEY #1, UT	COTTONWOOD, UT	138.00	138.00	Wood - SP	3.00		1
20	MID VALLEY, UT	90TH SOUTH, UT	138.00	138.00	Wood - H	9.00		1
21	MIDDLETON, UT	SAINT GEORGE, UT	138.00	138.00	Wood - H	1.00		1
22	MOAB, UT	PINTO, UT	138.00	138.00	Wood - H	68.00		1
23	NAUGHTON, WY	CANYON COMP, WY	138.00	138.00	Wood - H	36.00		1
24	NAUGHTON, WY	PAINTER, WY	138.00	138.00	Wood - H	48.00		1
25	NEBO, UT	DRY CREEK, UT	138.00	138.00	Wood - H	33.00		1
26	NUCOR STEEL, UT	WHEELON, UT	138.00	138.00	Wood - H	10.00		1
27	ONEIDA, ID	OVID, UT	138.00	138.00	Wood - H	23.00		1
28	ONIEDA, ID	GRACE, ID	138.00	138.00	Wood - H	19.00		1
29	GRINDING, UT	OQUIRRH, UT	138.00	138.00	Wood - SP	14.00		1
30	GRINDING, UT	TOOELE, UT	138.00	138.00	Wood - SP	7.00		1
31	OQUIRRH, UT	TOOELE, UT	138.00	138.00	Steel - SP	23.00		1
32	OQUIRRH, UT	BARNEY, UT	138.00	138.00	Wood - H	5.00		1
33	OQUIRRH, UT	BINGHAM CANYON, UT	138.00	138.00	Wood - H	8.00		1
34	PAINTER, UT	RAILROAD, UT	138.00	138.00	Wood - H	7.00		1
35	PAROWAN, UT	WEST CEDAR, UT	138.00	138.00	Wood - H	21.00		1
36					TOTAL	16,969.00	715.00	282

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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)	
1272 ACSR 45/7								1
1272 ACSR 45/7								2
795 ACSR 26/7								3
397.5 ACSR 26/7								4
250 CUHD /12								5
397.5 ACSR 26/7								6
397.5 ACSR 26/7								7
1272 AAC /61								8
795 AAC /37								9
1272 AAC /91								10
1272 AAC /61								11
500 AAC /19								12
								13
1272 ACSR 45/7								14
795 AAC 26/7								15
795 AAC 26/7								16
1272 ACSR /61								17
								18
								19
1272 ACSR 45/7								20
397.5 ACSR 26/7								21
397.5 ACSR 26/7								22
795 AAC 26/7								23
795 AAC 26/7								24
795 AAC 26/7								25
397.5 ACSR 26/7								26
336.4 ACSR 26/7								27
250 CUHD /12								28
795 AAC 45/7								29
796 AAC 45/7								30
1272 ACSR 45/7								31
795 AAC 26/7								32
1557.4 ACSR/TW								33
1272 ACSR 45/7								34
397.5 ACSR 26/7								35
	229,153,883	3,385,069,822	3,614,223,705	409,509	17,142,995	2,248,767	19,801,271	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	/ /	End of 2015/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	PARRISH, UT	TERMINAL #1, UT	138.00	138.00	Steel - SP	16.00		1
2	PARRISH, UT	TERMINAL #2, UT	138.00	138.00			14.00	1
3	PARRISH #105, UT	TERMINAL, UT	138.00	138.00	Steel - SP	14.00		1
4	PARRISH, UT	TAP TO N SALT LAKE, UT	138.00	138.00	Steel - SP		8.00	1
5	RAILROAD, UT	CANYON COMP, WY	138.00	138.00	Wood - H	17.00		1
6	CENTRAL (UAMPS) #2, UT	SAINT GEORGE, UT	138.00	138.00	Steel - SP	20.00		1
7	CENTRAL (UAMPS) #3, UT	SAINT GEORGE, UT	138.00	138.00	Steel - SP		20.00	1
8	RED BUTTE, UT	SAINT GEORGE, UT	138.00	138.00	Steel - SP	1.00		1
9	RED BUTTE, UT	WEST CEDAR, UT	138.00	138.00	Wood - H	49.00		1
10	RIVERDALE, UT	EAST LAYTON, UT	138.00	138.00	Steel - SP		7.00	1
11	SHICK, UT	PARRISH, UT	138.00	138.00	Wood - H		10.00	1
12	SILVER CREEK, UT	JORDANELLE, UT	138.00	138.00	Wood - SP	10.00		1
13	SPANISH FORK, UT	TANNER, UT	138.00	138.00	Wood - H	10.00		1
14	SUNRISE, UT	OQUIRRH, UT	138.00	138.00	Wood - SP		2.00	1
15	SYRACUSE, UT	CLEARFIELD SOUTH, UT	138.00	138.00	Steel - SP	1.00		1
16	SYRACUSE, UT	PARRISH, UT	138.00	138.00	Steel Tower	15.00		1
17	SYRACUSE, UT	ANGEL #1, UT	138.00	138.00			9.00	1
18	TAP TO ANGEL NORTH, UT	TAP TO PARRISH, UT	138.00	138.00	Wood - H	13.00		1
19	TAYLORSVILLE , UT	90TH SOUTH, UT	138.00	138.00	Wood - SP	6.00	2.00	1
20	TERMINAL, UT	KENNECOTT, UT	138.00	138.00	Steel - SP	9.00		1
21	TERMINAL, UT	ROWLEY, UT	138.00	138.00	Wood - H	53.00		1
22	TERMINAL, UT	MIDVALLEY #1, UT	138.00	138.00	Wood - H	7.00		1
23	TERMINAL, UT	MIDVALLEY #2, UT	138.00	138.00	Wood - H	7.00		1
24	TERMINAL, UT	TOOELE, UT	138.00	138.00	Wood - H	24.00	6.00	1
25	TERMINAL, UT	WEST VALLEY, UT	138.00	138.00	Wood - SP	7.00		1
26	THREEMILE KNOLL, ID	GRACE #1, ID	138.00	138.00	Wood - H	17.00		1
27	THREEMILE KNOLL, ID	GRACE #2, ID	138.00	138.00	Wood - H	17.00		1
28	THREEMILE KNOLL, ID	MONSANTO #1, ID	138.00	138.00	Wood - H	2.00		1
29	THREEMILE KNOLL, ID	MONSANTO #2, ID	138.00	138.00	Steel - SP	2.00		1
30	TIMP #1, UT	DYNAMO, UT	138.00	138.00	Steel - SP	2.00		1
31	TIMP #2, UT	DYNAMO, UT	138.00	138.00			2.00	1
32	TIMP, UT	HALE, UT	138.00	138.00	Steel - SP	4.00		1
33	TIMP, UT	SPANISH FORK, UT	138.00	138.00	Wood - H	23.00		1
34	TREASURETON, ID	GRACE, ID	138.00	138.00	Steel Tower	25.00		1
35	TREASURETON, ID	GRACE #2, ID	138.00	138.00			25.00	1
36					TOTAL	16,969.00	715.00	282

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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.
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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.
795 AAC 45/7								1
795 AAC 26/7								2
795 AAC 45/7								3
795 AAC 26/7								4
795 ACSR 26/7								5
1272 ACSR 45/7								6
1272 ACSR 45/7								7
1272 ACSR 45/7								8
397.5 ACSR 26/7								9
795 AAC 26/7								10
250 CUHD /12								11
795 AAC 26/7								12
1272 ACSR 45/7								13
								14
1272 ACSR 45/7								15
1272 ACSR 45/7								16
250 CUHD /12								17
795 AAC /37								18
795 AAC /37								19
795 AAC 26/7								20
795 AAC /37								21
1272 ACSR 45/7								22
1272 AAC /61								23
397.5 ACSR 26/7								24
								25
250 CUHD /12								26
1272 ACSR 45/7								27
1272 AAC /61								28
1272 ACSR 45/7								29
								30
								31
								32
								33
250 CUHD /12								34
250 CUHD /12								35
	229,153,883	3,385,069,822	3,614,223,705	409,509	17,142,995	2,248,767	19,801,271	36

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

TRANSMISSION LINE STATISTICS

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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	TREASURETON, ID	ONEIDA, ID	138.00	138.00	Wood - H	6.00		1
2	TRI-CITY, UT	SUNRISE, ID	138.00	138.00	Wood - SP	22.00		1
3	TRI-CITY, UT	BANGERTER, UT	138.00	138.00	Wood - SP	6.00	12.00	1
4	TRI-CITY, UT	WESTFIELD, UT	138.00	138.00	Wood - H	15.00		1
5	WEST CEDAR, UT	THREE PEAKS, UT	138.00	138.00	Wood - SP	20.00		1
6	WEST VALLEY, UT	OQUIRRH, UT	138.00	138.00	Wood - H	9.00		1
7	WESTFIELD, UT	HALE, UT	138.00	138.00	Wood - H	14.00		1
8	WHEELON, UT	AMERICAN FALLS, ID	138.00	138.00	Wood - H	86.00		1
9	WHEELON #1, UT	TREASURETON, ID	138.00	138.00	Steel Tower	29.00		1
10	WHEELON #2, UT	TREASURETON, ID	138.00	138.00			29.00	1
11	WHEELON #3, UT	TREASURETON, ID	138.00	138.00	Wood - H	29.00		1
12	FORT DOUGLAS, UT	MCCLELLAND, UT	138.00	138.00	Wood - SP	3.00		1
13	CAMERON, UT	MILFORD, UT	138.00	138.00	Wood - SP	25.00		1
14	EAGLE MOUNTAIN, UT	PONY EXPRESS, UT	138.00	138.00	Wood - SP	10.00		1
15	CLOVER, UT	BURRASTON PONDS	138.00	138.00	Wood - SP	2.00		1
16	CROYDON, UT	RAILROAD, WY	138.00	138.00	Wood - SP	38.00		1
17	GRAPHITE, UT	MOUNTAIN VIEW, UT	138.00	138.00	Wood - SP	1.00		1
18	HIGHLAND, UT	BULL RIVER (LEHI #5), UT	138.00	138.00	Wood - SP	5.00		1
19	138kV costs and expenses							
20								
21	Subtotal 138 kV					2,151.00	207.00	146
22								
23	All 115 kV Lines					1,662.00		
24								
25	All 69 kV Lines					2,954.00		
26								
27	All 57 kV Lines					113.00		
28								
29	All 46 kV Lines					2,541.00		
30								
31								
32								
33								
34								
35								
36					TOTAL	16,969.00	715.00	282

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION LINE STATISTICS (Continued)

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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
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.
250 CUHD /12								1
								2
								3
1272 ACSR 45/7								4
795 AAC 26/7								5
								6
795 AAC 26/7								7
250 CUHD /12								8
250 CUHD /12								9
250 CUHD /12								10
250 CUHD /12								11
								12
397.5 ACSR 26/7								13
795 ACSR 26/7								14
397.5 ACSR 26/7								15
1272 ACSR 45/7								16
397.5 ACSR 26/7								17
1272 ACSR 45/7								18
	23,026,009	356,517,639	379,543,648	139,649	2,514,220	156,582	2,810,451	19
								20
	23,026,009	356,517,639	379,543,648	139,649	2,514,220	156,582	2,810,451	21
								22
	5,102,293	187,284,252	192,386,545	23,728	2,378,644	416,438	2,818,810	23
								24
	7,272,689	272,505,105	279,777,794	72,709	3,531,003	251,656	3,855,368	25
								26
	46,327	10,883,923	10,930,250	22,222	142,597	3,430	168,249	27
								28
	10,058,852	251,925,669	261,984,521	77,513	2,568,538	64,948	2,710,999	29
								30
								31
								32
								33
								34
								35
	229,153,883	3,385,069,822	3,614,223,705	409,509	17,142,995	2,248,767	19,801,271	36

Schedule Page: 422 Line No.: 1 Column: a

Certain transmission lines reported on pages 422-423 are part of exchange agreements with various third parties. Refer to the footnotes on pages 328-330 of this FERC Form No. 1 for further discussion.

Schedule Page: 422 Line No.: 2 Column: a

The Dixonville - Meridian 500kV line is jointly owned by PacifiCorp and Bonneville Power Administration ("BPA"). Ownership of the line is as follows: PacifiCorp 50.0%, BPA 50.0%. Plant cost reported for this line reflects PacifiCorp'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 Alvey - Dixonville 500kV line is jointly owned by PacifiCorp and BPA. Ownership of the line is as follows: PacifiCorp 50.0%, BPA 50.0%. Plant cost reported for this line reflects PacifiCorp'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 Midpoint - Malin 500kV line is jointly owned by PacifiCorp and Idaho Power Company. Ownership of the line is as follows:

Designation	PacifiCorp	Idaho Power Company
Hemingway – Summer Lake	78.05%	21.95%
Midpoint – Hemingway	63.00%	37.00%

Plant cost and operation and maintenance costs reported for this line reflect PacifiCorp’s share.

Schedule Page: 422 Line No.: 8 Column: a

The Colstrip 4 - Switchyard 500kV line is jointly owned by PacifiCorp, NorthWestern Corporation, Puget Sound Energy, Avista Corporation 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 reflect PacifiCorp's share.

Schedule Page: 422 Line No.: 9 Column: a

The Colstrip - Broadview A 500kV line is jointly owned by PacifiCorp, NorthWestern Corporation, Puget Sound Energy, Avista Corporation 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 reflect PacifiCorp's share.

Schedule Page: 422 Line No.: 10 Column: a

The Colstrip - Broadview B 500kV line is jointly owned by PacifiCorp, NorthWestern Corporation, Puget Sound Energy, Avista Corporation 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 reflect PacifiCorp's share.

Schedule Page: 422 Line No.: 11 Column: a

Broadview - Townsend A 500kV line is jointly owned by PacifiCorp, NorthWestern Corporation, Puget Sound Energy, Avista Corporation 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 reflect PacifiCorp's share.

Schedule Page: 422 Line No.: 12 Column: a

Broadview - Townsend B 500kV line is jointly owned by PacifiCorp, NorthWestern Corporation, Puget Sound Energy, Avista Corporation 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 reflect PacifiCorp's share.

Schedule Page: 422 Line No.: 17 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422 Line No.: 18 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.1 Line No.: 4 Column: a

The Goshen - Kinport 345kV line is jointly owned by PacifiCorp and Idaho Power Company. Ownership of the line is as follows: PacifiCorp 81.69%, Idaho Power Company 18.31%. Plant cost and operation and maintenance costs reported for this line reflect PacifiCorp’s share.

Schedule Page: 422.1 Line No.: 9 Column: a

The Jim Bridger - Borah 345kV line is jointly owned by PacifiCorp and Idaho Power Company. Ownership of the line is as follows:

Designation	PacifiCorp	Idaho Power Company
Jim Bridger – Populus #1	70.83%	29.17%
Populus – Borah #1	70.83%	29.17%

Plant cost and operation and maintenance costs reported for this line reflect PacifiCorp’s share.

Schedule Page: 422.1 Line No.: 10 Column: a

The Jim Bridger - Kinport 345kV line is jointly owned by PacifiCorp and Idaho Power Company. Ownership of the line is as follows:

Designation	PacifiCorp	Idaho Power Company
Jim Bridger – Populus #2	70.83%	29.17%
Populus – Kinport	70.83%	29.17%

Plant cost and operation and maintenance costs reported for this line reflect PacifiCorp’s share.

Schedule Page: 422.1 Line No.: 19 Column: a

The Jim Bridger - Goshen 345kV line is jointly owned by PacifiCorp and Idaho Power Company. Ownership of the line is as follows: PacifiCorp 70.83%, Idaho Power Company 29.17%. Plant cost and operation and maintenance costs reported for this line reflect PacifiCorp’s share.

Schedule Page: 422.1 Line No.: 20 Column: a

The Borah - Midpoint #1 345kV line is jointly owned by PacifiCorp and Idaho Power Company. Ownership of the line designation Borah - Adelaide - Midpoint #1 is as follows: PacifiCorp 35.55%, Idaho Power Company 64.45%. Plant cost and operation and maintenance costs reported for this line reflect PacifiCorp’s share.

Schedule Page: 422.1 Line No.: 21 Column: a

The Borah - Midpoint #2 345kV line is jointly owned by PacifiCorp and Idaho Power Company. Ownership of the line designation Borah - Adelaide - Midpoint #2 is as follows: PacifiCorp 35.55%, Idaho Power Company 64.45%. Plant cost and operation and maintenance costs reported for this line reflect PacifiCorp’s share.

Schedule Page: 422.1 Line No.: 22 Column: a

The Kinport - Midpoint 345kV line is jointly owned by PacifiCorp and Idaho Power Company. Ownership of the line is as follows: PacifiCorp 26.82%, Idaho Power Company 73.18%. Plant cost and operation and maintenance costs reported for this line reflect PacifiCorp’s share.

Schedule Page: 422.2 Line No.: 2 Column: a

A 1.5 mile segment of the Casper - Dave Johnston 230kV line is jointly owned by PacifiCorp and Black Hills Power. Ownership of the line is as follows: PacifiCorp 43.75%, Black Hills Power 56.25%. Plant cost and operation and maintenance costs reported for this line reflect PacifiCorp's share.

Schedule Page: 422.2 Line No.: 2 Column: i

1557 ACSS/TW 45/7

Schedule Page: 422.2 Line No.: 17 Column: a

Complete name is Gonder (NV Energy), UT - NV State.

Schedule Page: 422.2 Line No.: 20 Column: a

The Hurricane - Walla Walla 230kV line is jointly owned by PacifiCorp and Idaho Power Company. Ownership of the line is as follows: PacifiCorp 59.17%, Idaho Power Company

40.83%. Plant cost and operation and maintenance costs reported for this line reflect PacifiCorp's share.

Schedule Page: 422.3 Line No.: 33 Column: a

The Big Grassy - Jefferson 161kV line is jointly owned by PacifiCorp and Idaho Power Company. Ownership of the line is as follows: PacifiCorp 62.24%, Idaho Power Company 37.76%. Plant cost and operation and maintenance costs reported for this line reflect PacifiCorp's share.

Schedule Page: 422.3 Line No.: 34 Column: a

The Antelope - Goshen 161kV line is jointly owned by PacifiCorp and Idaho Power Company. Ownership of the line is as follows: PacifiCorp 78.13%, Idaho Power Company 21.87%. Plant cost and operation and maintenance costs reported for this line reflect PacifiCorp's share.

Schedule Page: 422.4 Line No.: 8 Column: a

The Goshen - Jefferson 161kV line is jointly owned by PacifiCorp and Idaho Power Company. Ownership of the line is as follows: PacifiCorp 62.24%, Idaho Power Company 37.76%. Plant cost and operation and maintenance costs reported for this line reflect PacifiCorp's share.

Schedule Page: 422.4 Line No.: 20 Column: a

The Antelope - Scoville #1 138kV line is jointly owned by PacifiCorp and Idaho Power Company. Ownership of the line is as follows: PacifiCorp 33.33%, Idaho Power Company 66.67%. Plant cost and operation and maintenance costs reported for this line reflect PacifiCorp's share.

Schedule Page: 422.4 Line No.: 21 Column: a

The Antelope - Scoville #2 138kV line is jointly owned by PacifiCorp and Idaho Power Company. Ownership of the line is as follows: PacifiCorp 33.33%, Idaho Power Company 66.67%. Plant cost and operation and maintenance costs reported for this line reflect PacifiCorp's share.

Schedule Page: 422.4 Line No.: 25 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 13 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 18 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 19 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 33 Column: b

Complete name is Bingham Canyon (KCC), UT.

Schedule Page: 422.7 Line No.: 6 Column: a

The Central - Saint George 138kV line is jointly owned by PacifiCorp and Utah Associated Municipal Power Systems ("UAMPS"). Ownership of the line is as follows: PacifiCorp 54.62%, UAMPS 45.38%. Plant cost and operation and maintenance costs reported for this line reflect PacifiCorp's share.

Schedule Page: 422.7 Line No.: 7 Column: a

See footnote on page 422.7, line 6, column (a).

Schedule Page: 422.7 Line No.: 14 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 25 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 30 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 31 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 32 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 33 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 2 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 3 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 6 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 8 Column: a

The Wheelon - American Falls 138kV line is jointly owned by PacifiCorp and Idaho Power Company. Ownership of the line designation American Falls - Malad is as follows: PacifiCorp 96.38%, Idaho Power Company 3.62%. Plant cost and operation and maintenance costs reported for this line reflect PacifiCorp’s share.

Schedule Page: 422.8 Line No.: 12 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 15 Column: b

Complete name is Burraston Ponds Metering, UT.

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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	BORAH, ID	MIDPOINT #1, ID	79.00	Wood - H	6.00	1	1
2	BORAH, ID	MIDPOINT #2, ID	78.00	Wood - H	6.00	1	1
3	EAGLE MOUNTAIN, UT	PONY EXPRESS, UT	10.00	Wood - SP	15.00		
4	BIG GRASSY, ID	JEFFERSON, ID	21.00	Wood - H	9.00		
5	JIM BRIDGER, WY	GOSHEN, ID	226.00	Steel Tower	6.00		
6	KINPORT, ID	MIDPOINT, ID	113.00	Steel - SP	6.00	1	1
7	RED BUTTE, UT	SIGURD, UT	170.00	Steel - H	5.00		
8	CAMERON, UT	MILFORD, UT	25.00	Wood - SP	15.00	1	1
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
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37							
38							
39							
40							
41							
42							
43							
44	TOTAL		722.00		68.00	4	4

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
3-1272	ACSR	Vertical 14'	345		2,950,774	912,291		3,863,065	1
3-1272	ACSR	Vertical 14'	345		3,746,497	712,888		4,459,385	2
795	ACSR	Vertical 5'	138	804,037	1,809,097	3,326,200		5,939,334	3
250I	CU/ 18		161		50,429	32,757		83,186	4
2-1272	ACSR	Vertical 14'	345		3,101,285	2,883,299		5,984,584	5
2-1272	ACSR	Vertical 14'	345		2,337,702	1,640,115		3,977,817	6
2-954	ACSR		345	12,248,101	191,657,460	94,435,771		298,341,332	7
397.5	ACSR	Vertical 10'	138	206,159	3,410,427	2,887,035		6,503,621	8
									9
									10
									11
									12
									13
									14
									15
									16
									17
									18
									19
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									38
									39
									40
									41
									42
									43
				13,258,297	209,063,671	106,830,356		329,152,324	44

Schedule Page: 424 Line No.: 4 Column: j

Horizontal 14'

Schedule Page: 424 Line No.: 7 Column: j

Horizontal 14'

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	CALIFORNIA				
2	BELMONT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	BIG SPRINGS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	CASTELLA SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
5	CLEAR LAKE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	DOG CREEK SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
7	DORRIS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	FORT JONES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	GASQUET SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
10	GREENHORN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
11	HAMBURG SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
12	HAPPY CAMP SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	HORNBROOK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	INTERNATIONAL PAPER SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
15	LAKE EARL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	LITTLE SHASTA SUB	DISTRIBUTION-UNATTEN	69.00	7.20	
17	LUCERNE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
18	MACDOEL SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
19	MCCLOUD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	MILLER REDWOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	MONTAGUE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	MORRISON CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.50	
23	MOUNT SHASTA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	NEWELL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	NORTH DUNSMUIR SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	NORTHCREST SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	NUTGLADE SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
28	PATRICKS CREEK SUB	DISTRIBUTION-UNATTEN	115.00	7.20	
29	PEREZ SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	REDWOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	SCOTT BAR SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	SEIAD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	SHASTINA SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
34	SHOTGUN CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	SMITH RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	SNOW BRUSH SUB	DISTRIBUTION-UNATTEN	69.00	7.20	
37	SOUTH DUNSMUIR SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
38	TULELAKE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	TUNNEL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	WALKER BRYAN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
						1
25	1					2
6	1					3
1	3					4
4	3					5
	1					6
7	3					7
6	1					8
9	1					9
12	1					10
1	1					11
7	3					12
4	3					13
9	3					14
12	1					15
2	3					16
4	1					17
30	2					18
6	1					19
4	3					20
6	1					21
14	1					22
16	4					23
12	1					24
6	6					25
20	4					26
1	3					27
1	1					28
1	3					29
9	3					30
2	3					31
2	3					32
6	3					33
1	1					34
6	3					35
1	3					36
2	3					37
20	1					38
6	6					39
9	3					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	/ /	End of 2015/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	WEED SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
2	YUBA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	YUROK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	TOTAL		3082.00	465.96	
5	Number of Substations-42				
6					
7	ALTURAS SUB	T/D-UNATTENDED	115.00	69.00	
8	YREKA SUB	T/D-UNATTENDED	115.00	12.47	69.00
9	TOTAL		230.00	81.47	69.00
10	Number of Substations-2				
11					
12	COPCO #2 230 SUB	TRANSMISSION-ATTENDE	230.00	115.00	
13	COPCO #2 SUB	TRANSMISSION-ATTENDE	115.00	69.00	12.47
14	AGER SUB	TRANSMISSION-UNATTEN	115.00	69.00	
15	CRAG VIEW SUB	TRANSMISSION-UNATTEN	115.00	69.00	
16	DEL NORTE SUB	TRANSMISSION-UNATTEN	115.00	69.00	
17	WEED JUNCTION SUB	TRANSMISSION-UNATTEN	115.00	69.00	
18	Total		805.00	460.00	12.47
19	Number of Substations-6				
20					
21	IDAHO				
22	ALEXANDER	DISTRIBUTION-UNATTEN	46.00	12.47	
23	AMMON	DISTRIBUTION-UNATTEN	69.00	12.47	
24	ANDERSON	DISTRIBUTION-UNATTEN	69.00	12.47	
25	ARCO	DISTRIBUTION-UNATTEN	69.00	12.47	
26	ARIMO	DISTRIBUTION-UNATTEN	46.00	12.47	
27	BANCROFT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	BELSON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
29	BERENICE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	CAMAS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	CANYON CREEK SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
32	CHESTERFIELD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	CLEMENTS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	CLIFTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	COVE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	DOWNEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	DUBOIS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	EASTMONT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	EGIN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	EIGHT MILE SUB	DISTRIBUTION-UNATTEN	46.00	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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
25	1					1
4	3					2
4	3					3
323	99					4
						5
						6
35	4					7
95	2					8
130	6					9
						10
						11
500	2					12
51	4					13
5	3					14
19	3					15
150	2					16
37	3					17
762	17					18
						19
						20
						21
4	1					22
14	1					23
20	1					24
6	1					25
7	1					26
4	1					27
12	1					28
10	1					29
14	1					30
20	1					31
5	1					32
5	1					33
4	1					34
6	1					35
5	1					36
12	1					37
14	1					38
14	1					39
4	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	/ /	End of 2015/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	GEORGETOWN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
2	GRACE CITY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	HAMER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	HAYES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
5	HENRY SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
6	HOLBROOK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	HOOPES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	HORSLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	IDAHO FALLS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	INDIAN CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
11	JEFFCO SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
12	KETTLE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
13	LAVA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	LUND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	MCCAMMON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	MENAN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
17	MERRILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	MILLER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	MONTPELIER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	MOODY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	NEWDALE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	OSGOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	PRESTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	RAYMOND SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	RENO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	REXBURG SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	RIRIE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
28	ROBERTS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
29	RUBY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	SAND CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	SANDUNE SUB	DISTRIBUTION-UNATTEN	67.00	24.90	
32	SHELLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	SMITH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	SOUTH FORK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	SPUD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	ST. CHARLES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	SUGAR CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	SUNNYDELL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	TANNER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	TARGHEE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	

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	1					1
5	1					2
14	1					3
9	1					4
1	1					5
6	1					6
9	1					7
4	1					8
20	1					9
3	1					10
22	1					11
14	1					12
6	1					13
5	1					14
3	1					15
10	1					16
20	1					17
5	1					18
8	1					19
14	1					20
20	1					21
20	1					22
12	1					23
2	1					24
20	1					25
32	2					26
9	1					27
8	1					28
7	1					29
40	2					30
30	1					31
20	1					32
20	1					33
14	1					34
8	1					35
5	1					36
12	1					37
13	1					38
4	1					39
4	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	/ /	End of 2015/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	THORNTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
2	UCON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	WATKINS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	WEBSTER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
5	WESTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	WINDSPER SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
7	TOTAL		4000.00	867.43	
8	Number of Substations-65				
9					
10	CINDER BUTTE SUB	T/D-UNATTENDED	161.00	12.47	
11	MALAD SUB	T/D-UNATTENDED	138.00	46.00	12.47
12	MUD LAKE SUB	T/D-UNATTENDED	69.00	12.47	
13	RIGBY SUB	T/D-UNATTENDED	161.00	12.47	69.00
14	SAINT ANTHONY SUB	T/D-UNATTENDED	69.00	46.00	12.47
15	TOTAL		598.00	129.41	93.94
16	Number of Substations-5				
17					
18	AMPS SUB	TRANSMISSION-UNATTEN	230.00	69.00	12.47
19	ANTELOPE SUB	TRANSMISSION-UNATTEN	230.00	161.00	12.47
20	ASHTON PLANT	TRANSMISSION-UNATTEN	46.00	12.47	2.40
21	BIG GRASSY SUB	TRANSMISSION-UNATTEN	161.00	69.00	
22	BONNEVILLE SUB	TRANSMISSION-UNATTEN	161.00	69.00	
23	CONDA SUB	TRANSMISSION-UNATTEN	138.00	46.00	
24	FISH CREEK SUB	TRANSMISSION-UNATTEN	161.00	46.00	
25	FRANKLIN SUB	TRANSMISSION-UNATTEN	138.00	46.00	
26	GOSHEN SUB	TRANSMISSION-UNATTEN	345.00	161.00	69.00
27	GRACE SUB	TRANSMISSION-UNATTEN	161.00	138.00	12.50
28	JEFFERSON SUB	TRANSMISSION-UNATTEN	161.00	69.00	
29	MIDPOINT SUB	TRANSMISSION-UNATTEN	500.00	345.00	
30	OVID SUB	TRANSMISSION-UNATTEN	138.00	69.00	
31	SCOVILLE SUB	TRANSMISSION-UNATTEN	138.00	69.00	
32	SUGARMILL SUB	TRANSMISSION-UNATTEN	161.00	46.00	69.00
33	THREEMILE KNOLL SUB	TRANSMISSION-UNATTEN	345.00	138.00	46.00
34	TREASURETON SUB	TRANSMISSION-UNATTEN	230.00	138.00	
35	TOTAL		3444.00	1691.47	223.84
36	Number of Substations-17				
37					
38	MONTANA				
39	BROADVIEW SUB	TRANSMISSION-UNATTEN	500.00	230.00	
40	COLSTRIP SUB	TRANSMISSION-UNATTEN	500.00	230.00	

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.
7	1					1
7	1					2
14	1					3
20	1					4
4	1					5
20	1					6
736	67					7
						8
						9
30	1					10
71	4	1				11
14	1					12
189	4					13
40	2					14
344	12	1				15
						16
						17
75	1					18
445	3					19
15	1					20
67	1					21
67	1					22
67	1					23
25	3					24
75	1					25
908	4					26
217	2					27
233	3					28
1500	1					29
30	1					30
76	2					31
168	3					32
775	2					33
533	2					34
5276	32					35
						36
						37
						38
32	2					39
68	2					40

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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	YELLOWTAIL SUB	TRANSMISSION-UNATTEN	230.00	161.00	
2	TOTAL		1230.00	621.00	
3	Number of Substations-3				
4					
5	OREGON				
6	26TH STREET	DISTRIBUTION-UNATTEN	20.80	4.16	
7	35TH STREET	DISTRIBUTION-UNATTEN	20.80	2.40	
8	AGNESS AVE	DISTRIBUTION-UNATTEN	115.00	12.47	
9	ALDERWOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	ARLINGTON	DISTRIBUTION-UNATTEN	69.00	12.47	
11	ATHENA	DISTRIBUTION-UNATTEN	69.00	12.47	
12	BANDON TIE SUB	DISTRIBUTION-UNATTEN	20.80	12.47	
13	BEACON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	BEALL LANE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
15	BEATTY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	BELKNAP SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
17	BLALOCK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	BLOSS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
19	BLY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	BOISE CASCADE SUB	DISTRIBUTION-UNATTEN	69.00	11.00	
21	BONANZA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	BOND STREET SUB	DISTRIBUTION-UNATTEN	69.00	12.50	
23	BROOKHURST SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
24	BROWNSVILLE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
25	BRYANT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	BUCHANAN SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
27	BUCKAROO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
28	CAMPBELL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
29	CANNON BEACH SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
30	CANYONVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
31	CARNES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	CASEBEER SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
33	CAVEMAN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
34	CHERRY LANE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	CHILOQUIN MARKET SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	CHINA HAT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	CIRCLE BLVD SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
38	CLEVELAND AVE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	CLOAKE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
40	COBURG SUB	DISTRIBUTION-UNATTEN	69.00	20.80	

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.
100	1					1
200	5					2
						3
						4
						5
5	1					6
30	6					7
25	1					8
45	2					9
5	1					10
9	1					11
8	3	1				12
11	3					13
25	1					14
6	1					15
40	2					16
2	3					17
32	2					18
8	3					19
3	1					20
8	3					21
25	1					22
50	2					23
13	1					24
34	2					25
45	2					26
34	2					27
20	2					28
13	1					29
25	1					30
9	3					31
20	1					32
45	2					33
25	1					34
6	3					35
25	1					36
80	2					37
45	2					38
20	1					39
10	3					40

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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	COLISEUM SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
2	COLUMBIA SUB	DISTRIBUTION-UNATTEN	115.00	12.47	57.00
3	COOS RIVER SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
4	COQUILLE SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
5	CREEK SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
6	CROOKED RIVER RANCH SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
7	CROWFOOT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
8	CULLY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
9	CULVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	DAIRY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
11	DALLAS SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
12	DALREED SUB	DISTRIBUTION-UNATTEN	230.00	34.40	
13	DESCHUTES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	DEVILS LAKE SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
15	DIXON SUB	DISTRIBUTION-UNATTEN	115.00	4.16	
16	DODGE BRIDGE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
17	DOWELL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
18	EASY VALLEY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
19	EMPIRE SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
20	ENTERPRISE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	FERN HILL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
22	FIELDER CREEK SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
23	FOOTHILLS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	FRALEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	GARDEN VALLEY SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
26	GAZLEY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
27	GLENDALE SUB	DISTRIBUTION-UNATTEN	230.00	12.47	
28	GLENEDEN SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
29	GLIDE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
30	GOLD HILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	GORDON HOLLOW SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	GOSHEN SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
33	GRANT STREET SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
34	GRASS VALLEY SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
35	GREEN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	GRIFFIN CREEK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
37	HAMAKER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	HARRISBURG SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
39	HENLEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	HERMISTON 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.
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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.
9	2					1
55	2	1				2
20	1					3
40	2					4
5	1					5
25	2					6
20	1					7
25	1					8
13	1					9
25	1					10
50	2					11
95	4					12
25	1					13
50	2					14
7	1					15
13	1					16
20	1					17
45	2					18
20	1					19
19	2					20
12	1					21
25	1					22
21	4					23
5	3					24
20	1					25
8	4					26
25	2					27
6	1					28
12	1					29
11	3					30
6	1					31
20	1					32
45	2					33
1	4					34
25	1					35
20	1					36
8	3					37
13	1					38
6	3					39
40	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	/ /	End of 2015/Q4

SUBSTATIONS

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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	HILLVIEW SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
2	HINKLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	HOLLADAY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
4	HOLLYWOOD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
5	HOOD RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	HORNET SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	HUMBUG CREEK SUB	DISTRIBUTION-UNATTEN	67.00	12.50	
8	HUNTERS CIRCLE TEMP SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	ILLAHEE FLATS SUB	DISTRIBUTION-UNATTEN	115.00	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	LANCASTER SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
22	LEBANON SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
23	LINCOLN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
24	LOCKHART SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
25	LYONS SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
26	MADRAS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	MALLORY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
28	MARYS RIVER SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
29	MEDCO SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
30	MEDFORD	DISTRIBUTION-UNATTEN	115.00	12.47	
31	MERLIN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
32	MERRILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	MINAM SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	MODOC SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	MORO SUB	DISTRIBUTION-UNATTEN	20.80	2.40	
36	MURDER CREEK SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
37	MYRTLE CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	MYRTLE POINT SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
39	NELSCOTT SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
40	NEW O'BRIEN SUB	DISTRIBUTION-UNATTEN	115.00	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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
45	2					1
20	1					2
75	3					3
50	2					4
40	2					5
20	1					6
9	1					7
12	1					8
2	1					9
20	1					10
75	2					11
12	1					12
20	1					13
20	1					14
6	1	1				15
22	2					16
3	3					17
40	2					18
6	1					19
50	2					20
12	3					21
40	2					22
105	3					23
40	2					24
25	2					25
25	2					26
25	1					27
20	1					28
20	1					29
67	8					30
45	2					31
17	6					32
	1					33
6	3					34
2	3					35
100	4					36
14	1					37
9	1					38
4	1					39
9	1					40

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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	OAK KNOLL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
2	OAKLAND SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
3	OREMET SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
4	OVERPASS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
5	PALLETTE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
6	PARK STREET SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
7	PARKROSE SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
8	PENDLETON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	PILOT ROCK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	POWELL BUTTE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
11	PRINEVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
12	PROVOLT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	QUEEN AVE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
14	RED BLANKET SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
15	REDMOND SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
16	RIDDLE VENEER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
17	ROGUE RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	ROSEBURG SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
19	ROSS AVE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	ROXY ANN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
21	RUCH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	RUNNING Y SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
23	RUSSELLVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
24	SCENIC SUB	DISTRIBUTION-UNATTEN	115.00	12.47	69.00
25	SCIO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	SEASIDE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
27	SELMA SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
28	SHASTA WAY SUB	DISTRIBUTION-UNATTEN	12.47	4.16	
29	SHEVLIN PARK SUB	DISTRIBUTION-UNATTEN	69.00	12.50	
30	SIMTAG BOOSTER PUMP	DISTRIBUTION-UNATTEN	34.50	4.16	
31	SOUTH DUNES SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
32	SOUTHGATE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
33	SPRAGUE RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	STATE STREET SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
35	STAYTON SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
36	STEAMBOAT SUB	DISTRIBUTION-UNATTEN	115.00	7.20	
37	STEVENS ROAD SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
38	SUTHERLIN SUB	DISTRIBUTION-UNATTEN	115.00	12.00	
39	SWEET HOME SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
40	TAKELMA SUB	DISTRIBUTION-UNATTEN	115.00	20.80	

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
8	1					2
75	2					3
45	2					4
1	1	1				5
40	2					6
39	2					7
46	7	1				8
22	2					9
12	1					10
50	2					11
11	3					12
50	2					13
2	3					14
50	2					15
25	1					16
25	2					17
50	2					18
9	3					19
25	1					20
9	1					21
9	1					22
45	2					23
70	3					24
8	1					25
40	2					26
9	1					27
2	3					28
25	1					29
19	2					30
9	1					31
20	1					32
7	3					33
40	2					34
55	2					35
	1					36
50	2					37
25	1					38
42	2					39
12	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	/ /	End of 2015/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	TALENT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
2	TEXUM SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	TILLER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
4	TOLO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
5	TURKEY HILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	UMAPINE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	UMATILLA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	VERNON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	VILAS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
10	VILLAGE GREEN SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
11	VINE STREET SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
12	WALLOWA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	WARM SPRINGS SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
14	WARRENTON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
15	WASCO SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
16	WECOMA BEACH SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
17	WESTERN KRAFT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
18	WESTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	WESTSIDE HYDRO/SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	WEYERHAUSER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	WHITE CITY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
22	WILLOW COVE SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
23	WINSTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	YEW AVENUE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
25	YOUNGS BAY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
26	TOTAL		15660.27	2511.44	195.00
27	Number of Substations-180				
28					
29	ALBINA SUB	T/D-UNATTENDED	115.00	12.47	69.00
30	APPLEGATE SUB	T/D-UNATTENDED	115.00	69.00	12.47
31	ASHLAND SUB	T/D-UNATTENDED	115.00	69.00	12.47
32	BEND PLANT SUB	T/D-UNATTENDED	69.00	13.09	12.47
33	CAVE JUNCTION SUB	T/D-UNATTENDED	115.00	12.47	69.00
34	HAZELWOOD SUB	T/D-UNATTENDED	115.00	69.00	12.47
35	KNOTT SUB	T/D-UNATTENDED	115.00	12.47	57.00
36	MILE HI SUB	T/D-UNATTENDED	115.00	69.00	12.47
37	PILOT BUTTE SUB	T/D-UNATTENDED	230.00	69.00	12.47
38	RIDDLE SUB	T/D-UNATTENDED	115.00	69.00	
39	SAGE ROAD SUB	T/D-UNATTENDED	115.00	12.47	
40	WINCHESTER SUB	T/D-UNATTENDED	115.00	12.47	69.00

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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	2					1
25	1					2
1	1					3
11	1					4
13	3					5
20	1					6
25	2					7
50	2					8
25	1					9
40	2					10
20	1					11
7	1					12
12	3					13
25	2					14
2	3					15
3	1					16
50	2					17
22	2					18
22	9					19
40	2					20
60	3					21
28	3					22
22	3					23
25	1					24
37	2					25
4609	346	5				26
						27
						28
177	9					29
65	2					30
70	2					31
31	3					32
70	2					33
106	3					34
162	5					35
39	4					36
400	4					37
75	2					38
40	2					39
75	5					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	/ /	End of 2015/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	TOTAL		1449.00	489.44	338.82
2	Number of Substations-12				
3					
4	LEMOLO #1 HYDRO	TRANSMISSION-ATTENDE	11.50	12.50	
5	CALAPOOYA SUB	TRANSMISSION-UNATTEN	230.00	69.00	
6	CHILOQUIN SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
7	COLD SPRINGS SUB	TRANSMISSION-UNATTEN	230.00	69.00	2.40
8	COVE SUB	TRANSMISSION-UNATTEN	230.00	69.00	
9	DIAMOND HILL SUB	TRANSMISSION-UNATTEN	230.00	69.00	
10	DIXONVILLE 115/230 SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
11	DIXONVILLE 500 SUB	TRANSMISSION-UNATTEN	500.00	230.00	
12	FISH HOLE SUB	TRANSMISSION-UNATTEN	115.00	69.00	
13	FRY SUB	TRANSMISSION-UNATTEN	230.00	115.00	
14	GRANTS PASS SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
15	GREEN SPRINGS PLANT/SUB	TRANSMISSION-UNATTEN	115.00	69.00	
16	HURRICANE SUB	TRANSMISSION-UNATTEN	230.00	69.00	2.40
17	ISTHMUS SUB	TRANSMISSION-UNATTEN	230.00	115.00	
18	KENNEDY SUB	TRANSMISSION-UNATTEN	69.00	57.00	
19	KLAMATH FALLS SUB	TRANSMISSION-UNATTEN	230.00	69.00	
20	LONE PINE SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
21	MALIN SUB	TRANSMISSION-UNATTEN	500.00	230.00	69.00
22	MERIDIAN SUB	TRANSMISSION-UNATTEN	500.00	230.00	
23	MONPAC SUB	TRANSMISSION-UNATTEN	115.00	69.00	
24	NICKEL MOUNTAIN SUB	TRANSMISSION-UNATTEN	230.00	115.00	
25	PARRISH GAP SUB	TRANSMISSION-UNATTEN	230.00	69.00	12.47
26	PONDEROSA SUB	TRANSMISSION-UNATTEN	230.00	115.00	
27	PROSPECT CENTRAL SUB	TRANSMISSION-UNATTEN	115.00	69.00	
28	ROBERTS CREEK SUB	TRANSMISSION-UNATTEN	115.00	69.00	
29	TROUTDALE SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
30	TUCKER SUB	TRANSMISSION-UNATTEN	115.00	69.00	
31	WHETSTONE SUB	TRANSMISSION-UNATTEN	230.00	115.00	12.47
32	TOTAL		6180.50	2806.50	443.74
33	Number of Substations-28				
34					
35	UTAH				
36	106TH SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
37	118TH SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
38	23RD ST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	70TH SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
40	ALTAVIEW SUB	DISTRIBUTION-UNATTEN	46.00	12.47	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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.
1310	43					1
						2
						3
2	3	1				4
75	1					5
119	4					6
66	2					7
67	3					8
75	1					9
343	6					10
650	3	1				11
7	3					12
500	2					13
473	5					14
19	3					15
29	2					16
250	1					17
33	1					18
251	6	1				19
733	10					20
775	4	1				21
1300	6	1				22
50	1					23
114	1					24
150	1					25
500	2					26
30	3					27
50	1					28
500	3					29
100	2					30
250	1					31
7511	81	5				32
						33
						34
						35
30	1					36
30	1					37
12	1					38
30	1					39
45	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	AMALGA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	AMERICAN FORK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
3	ARAGONITE	DISTRIBUTION-UNATTEN	46.00	7.20	
4	AURORA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	BANGERTER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
6	BEAR RIVER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	BENJAMIN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
8	BINGHAM SUB	DISTRIBUTION-UNATTEN	46.00	7.62	
9	BLUE CREEK	DISTRIBUTION-UNATTEN	46.00	12.47	
10	BLUFF SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
11	BLUFFDALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	BOTHWELL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	BRIAN HEAD SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
14	BRICKYARD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	BRIGHTON SUB	DISTRIBUTION-UNATTEN	46.00	24.90	
16	BROOKLAWN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	BRUNSWICK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	BURTON SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
19	BUSH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	CANNON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	CANYONLANDS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	CAPITOL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	CARBIDE SUB	DISTRIBUTION-UNATTEN	69.00	7.20	
24	CARBONVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	CARLISLE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
26	CASTO SUBSTATION	DISTRIBUTION-UNATTEN	46.00	12.47	
27	CENTERVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	CENTRAL SUB	DISTRIBUTION-UNATTEN	43.80	12.47	
29	CHAPEL HILL SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
30	CHERRYWOOD SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
31	CIRCLEVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	CLEAR CREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	CLEAR LAKE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	CLEARFIELD SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
35	CLINTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
36	CLIVE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	COALVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	COLD WATER CANYON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
39	COLEMAN SUB	DISTRIBUTION-UNATTEN	138.00	69.00	12.47
40	COLTON WELL SUB	DISTRIBUTION-UNATTEN	46.00	2.40	

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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
11	1					1
30	1					2
1	1					3
3	1					4
50	2					5
17	2					6
2	1					7
25	1					8
2	3					9
1	3					10
9	1					11
4	1					12
14	1					13
9	1					14
29	2					15
6	1					16
60	3					17
11	3					18
9	1					19
12	1					20
1	1					21
20	1					22
3	1					23
6	1					24
30	1					25
25	1					26
22	1					27
9	1					28
30	1					29
50	2					30
3	1					31
4	1					32
	3					33
60	2					34
50	2					35
4	1					36
6	1					37
30	1					38
106	4					39
1	3					40

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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	COMMERCE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
2	COPPER HILLS SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
3	CORINNE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	COVE FORT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	COZYDALE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
6	CROSS HOLLOW SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
7	CUDAHY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
8	DAMMERON VALLEY SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
9	DECKER LAKE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
10	DELLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	DELTA SUB	DISTRIBUTION-UNATTEN	46.00	69.00	
12	DEWEYVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	DIMPLE DELL SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
14	DRAPER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	EAST BENCH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
16	EAST HYRUM SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	EAST LAYTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
18	EAST MILLCREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	EDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	ELBERTA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	ELK MEADOWS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	ELSINORE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	EMERY CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	EMIGRATION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	ENOCH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
26	ENTERPRISE VALLEY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
27	EUREKA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	FARMINGTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
29	FAYETTE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	FERRON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	FIELDING SUB	DISTRIBUTION-UNATTEN	46.00	12.00	
32	FIFTH WEST SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
33	FLUX SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	FOOL CREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	FORT DOUGLAS	DISTRIBUTION-UNATTEN	138.00	13.20	
36	FOUNTAIN GREEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	FREEDOM SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
38	FRUIT HEIGHTS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	GARDEN CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	GATEWAY 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.
30	1					1
30	1					2
3	1					3
2	3					4
30	1					5
22	1					6
30	1					7
42	1					8
55	2					9
6	1					10
48	3					11
4	1					12
60	2					13
23	2					14
30	1					15
6	1					16
60	2					17
20	1					18
19	2					19
5	1					20
3	1					21
2	1					22
3	3					23
25	1					24
14	1					25
10	1					26
3	1					27
30	1					28
1	2					29
5	1					30
6	1					31
50	2					32
4	1					33
2	1					34
40	1					35
7	1					36
	1					37
22	1					38
12	1					39
14	1	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	GOLD RUSH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
2	GORDON AVENUE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
3	GOSHEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	GRANGER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	GRANTSVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	GUNNISON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	HAMMER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
8	HAVASU SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	HELPER CITY SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
10	HENEFER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	HERRIMAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
12	HIGHLAND DIST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	HOGGARD SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
14	HOLDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	HOLLADAY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	HUNTER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	HUNTINGTON CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	IRON MOUNTAIN SUB	DISTRIBUTION-UNATTEN	34.50	7.20	
19	IRONTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	IVINS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	JORDAN NARROWS SUB	DISTRIBUTION-UNATTEN	46.00	2.40	
22	JORDAN PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
23	JORDANELLE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
24	JUAB SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	JUNCTION SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	KAIBAB SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	KAMAS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	KEARNS SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
29	KENSINGTON SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
30	KYUNE SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
31	LAKE PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
32	LAYTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	LEGRANDE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	LEWISTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	LINCOLN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	LINDON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	LISBON SUB	DISTRIBUTION-UNATTEN	70.60	12.47	
38	LOAFER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	LOGAN CANYON SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
40	LONE TREE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
30	1					1
30	1					2
2	1					3
50	2					4
23	1					5
11	2					6
60	2					7
3	1					8
3	3					9
4	1					10
30	1					11
25	1					12
50	2					13
4	1					14
32	2					15
22	1					16
12	2					17
1	1					18
2	1					19
22	1					20
13	2					21
30	1					22
30	1					23
4	1					24
3	1					25
5	1					26
7	1					27
60	2					28
7	1					29
	1					30
53	2					31
40	2					32
2	1					33
14	1					34
20	1					35
20	1					36
3	1					37
	1					38
1	1					39
20	1					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	LOWER BEAVER SUB	DISTRIBUTION-UNATTEN	46.00	6.60	
2	LYNNDYL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	MAESER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	MAGNA SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
5	MANILA SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
6	MANTUA SUB	DISTRIBUTION-UNATTEN	44.00	12.47	
7	MAPLETON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
8	MARRIOTT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	MARYSVALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	MATHIS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	MCCORNICK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	MCKAY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	MEADOWBROOK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	46.00
14	MEDICAL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	MIDLAND SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
16	MIDVALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	MILFORD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	MILFORD TV SUB	DISTRIBUTION-UNATTEN	46.00	13.20	
19	MINERSVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	MOAB CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	MONTEZUMA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	MOORE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	MORGAN SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
24	MORONI SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	MOSS JUNCTION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	MOUNTAIN DELL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
27	MOUNTAIN GREEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	MYTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
29	NEW HARMONY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	NEWGATE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	NEWTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	NIBLEY SUB	DISTRIBUTION-UNATTEN	138.00	24.90	
33	NORTH BENCH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	NORTH FIELDS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	NORTH LOGAN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	NORTH OGDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	NORTH SALT LAKE SUB	DISTRIBUTION-UNATTEN	46.00	13.20	
38	NORTHEAST SUB	DISTRIBUTION-UNATTEN	46.00	12.50	
39	NORTHRIDGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	OAKLAND AVE SUB	DISTRIBUTION-UNATTEN	46.00	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.
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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.
1	1					1
4	1					2
12	1					3
30	1					4
22	1					5
2	1					6
14	1					7
20	1					8
3	1					9
9	1					10
6	1					11
20	1					12
42	2					13
57	4					14
30	1					15
25	1					16
14	1					17
	1					18
2	1					19
19	2					20
12	1					21
3	1					22
7	2					23
6	1					24
6	3					25
5	1					26
6	1					27
6	1					28
7	1					29
20	1					30
5	1					31
14	1					32
25	1					33
2	1					34
25	1					35
22	1					36
25	1					37
45	2					38
14	1					39
24	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	OAKLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	OLYMPUS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	OPHIR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	ORANGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	ORANGEVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	OREM SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	PACK CREEK RESERVOIR	DISTRIBUTION-UNATTEN	46.00	12.47	
8	PANGUITCH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	PARIETTE SUB	DISTRIBUTION-UNATTEN	69.00	24.94	
10	PARK CITY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	PARKSIDE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
12	PARKWAY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
13	PARLEYS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	PELICAN POINT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	PINE CANYON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
16	PINE CREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	PINNACLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	PLAIN CITY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
19	PLEASANT GROVE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
20	PLEASANT VIEW SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	PONY EXPRESS SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
22	PORTER ROCKWELL SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
23	PROMONTORY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	QUAIL CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	QUARRY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
26	QUICHAPA SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
27	RAINS SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
28	RANDOLPH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	RASMUSON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	RATTLESNAKE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
31	RED MOUNTAIN SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
32	RED ROCK SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
33	REDWOOD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	RESEARCH PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	RICH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	RICHFIELD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	RICHMOND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	RIDGELAND SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
39	RITER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	ROCK CANYON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
6	1					1
22	1					2
3	1					3
20	1					4
14	1					5
48	2					6
4	1					7
5	1					8
14	1					9
42	2					10
60	2					11
50	2					12
16	2					13
6	1					14
55	2					15
2	1					16
14	1					17
22	1					18
25	1					19
14	1					20
60	2					21
30	1					22
2	1					23
4	1					24
60	2					25
4	1					26
15	1					27
2	1					28
1	3					29
14	1					30
12	1					31
3	1					32
45	2					33
45	2					34
5	1					35
22	2					36
11	1					37
40	2					38
20	1					39
5	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	/ /	End of 2015/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	ROCKVILLE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
2	ROCKY POINT	DISTRIBUTION-UNATTEN	138.00	13.20	
3	ROSE PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	ROYAL SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
5	SALINA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	SANDY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
7	SARATOGA SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
8	SCIPIO SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	SCOFIELD RESERVOIR SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
10	SCOFIELD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	SECOND STREET SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	SEGO CANYON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	SEVEN MILE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	SHARON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	SHIVWITS SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
16	SHORELINE SUB	DISTRIBUTION-UNATTEN	138.00	13.20	
17	SIXTH SOUTH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	SKULL VALLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	SKYPARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	12.47
20	SNARR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	SNOWVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	SNYDERVILLE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
23	SOLDIER SUMMIT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	SOUTH JORDAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
25	SOUTH MILFORD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	SOUTH MOUNTAIN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
27	SOUTH OGDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	SOUTH PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
29	SOUTH WEBER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
30	SOUTHWEST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	SPANISH VALLEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	SPRINGDALE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
33	ST. JOHNS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	STANSBURY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	SUMMIT CREEK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
36	SUMMIT PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	SUNRISE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
38	SUPERIOR SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	SUTHERLAND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	TAMARISK SUB	DISTRIBUTION-UNATTEN	138.00	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.
4	1					1
30	1					2
24	3					3
	3					4
11	1					5
60	2					6
60	2					7
1	3					8
1	1					9
1	3					10
13	2					11
14	1					12
	1					13
20	1					14
6	1					15
60	2					16
20	1					17
2	1					18
40	1					19
40	2					20
5	1					21
60	2					22
12	1					23
60	2					24
20	2					25
60	2					26
25	1					27
30	1					28
22	1					29
22	2					30
6	1					31
4	1					32
4	1					33
20	1					34
14	1					35
7	1					36
60	2					37
8	1					38
6	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 (2) [ ] A Resubmission	/ /	End of 2015/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	TAYLOR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	THIEF CREEK SUB	DISTRIBUTION-UNATTEN	138.00	24.90	
3	THIRD WEST SUB	DISTRIBUTION-UNATTEN	138.00	13.20	
4	THIRTEENTH SOUTH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	TOOELE DEPOT SUB	DISTRIBUTION-UNATTEN	46.00	12.50	
6	TOQUERVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	34.50
7	UINTAH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
8	UNION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	VALLEY CENTER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	VERMILLION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	VERNAL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
12	VICKERS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	VINEYARD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	WALLSBURG SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
15	WALNUT GROVE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
16	WARREN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
17	WASATCH STATE PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	WASHAKIE SUB	DISTRIBUTION-UNATTEN	138.00	4.16	
19	WELBY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	WELFARE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	WEST COMMERCIAL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	WEST JORDAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
23	WEST OGDEN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
24	WEST ROY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	WEST TEMPLE SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
26	WESTWATER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	WHITE MESA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
28	WHITE ROCK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
29	WILLOWCREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	WILLOWRIDGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	WINCHESTER HILLS SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
32	WINKLEMAN SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
33	WOLF CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	WOOD CROSS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	WOODRUFF SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	TOTAL		20214.40	3548.08	105.44
37	Number of Substations-280				
38					
39	90TH SOUTH SUB	T/D-UNATTENDED	345.00	138.00	12.47
40	ANGEL SUB	T/D-UNATTENDED	138.00	12.47	46.00

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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
14	1					1
14	1					2
100	2					3
22	1					4
25	1					5
34	2					6
39	2					7
50	2					8
22	1					9
3	1					10
33	2					11
2	1					12
25	1					13
13	1					14
30	1					15
30	1					16
2	3					17
14	1					18
42	2					19
10	1					20
22	1					21
28	1					22
60	2					23
25	1					24
60	3					25
5	1					26
14	1					27
30	1					28
1	1					29
14	1					30
4	1					31
	1					32
6	1					33
20	1					34
2	1					35
5578	381	2				36
						37
						38
1572	5					39
135	3					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	/ /	End of 2015/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	BDO SUBSTATION	T/D-UNATTENDED	138.00	12.47	
2	BUTLERVILLE SUB	T/D-UNATTENDED	138.00	46.00	12.47
3	CENTENNIAL SUB	T/D-UNATTENDED	138.00	12.47	
4	COTTONWOOD SUB	T/D-UNATTENDED	138.00	12.47	46.00
5	DECADE SUB	T/D-UNATTENDED	138.00	12.47	
6	DUMAS SUB	T/D-UNATTENDED	138.00	12.47	
7	EMMA PARK SUBSTATION	T/D-UNATTENDED	138.00	12.47	
8	GROW SUB	T/D-UNATTENDED	138.00	12.47	46.00
9	HALE SUB	T/D-UNATTENDED	138.00	46.00	12.47
10	HIGHLAND SUB	T/D-UNATTENDED	138.00	12.47	46.00
11	JORDAN SUB	T/D-UNATTENDED	138.00	46.00	12.47
12	JUDGE SUB	T/D-UNATTENDED	46.00	12.47	
13	MCCLELLAND SUB	T/D-UNATTENDED	138.00	46.00	12.47
14	MORTON COURT SUB	T/D-UNATTENDED	138.00	12.47	
15	OQUIRRH SUB	T/D-UNATTENDED	345.00	46.00	138.00
16	PARRISH SUB	T/D-UNATTENDED	138.00	12.47	46.00
17	PIONEER PLANT	T/D-UNATTENDED	138.00	12.47	
18	RIVERDALE SUB	T/D-UNATTENDED	138.00	46.00	12.47
19	SEVIER SUB	T/D-UNATTENDED	138.00	46.00	12.47
20	SILVER CREEK SUB	T/D-UNATTENDED	138.00	12.47	46.00
21	SOUTHEAST SUB	T/D-UNATTENDED	138.00	12.47	46.00
22	SYRACUSE SUB	T/D-UNATTENDED	345.00	46.00	138.00
23	TAYLORSVILLE SUB	T/D-UNATTENDED	138.00	46.00	12.47
24	TERMINAL SUB	T/D-UNATTENDED	345.00	46.00	138.00
25	TIMP SUB	T/D-UNATTENDED	138.00	46.00	12.47
26	TOOELE SUB	T/D-UNATTENDED	138.00	46.00	12.47
27	TRI CITY SUB	T/D-UNATTENDED	138.00	12.47	
28	WEST VALLEY SUB	T/D-UNATTENDED	138.00	12.47	
29	WESTFIELD SUB	T/D-UNATTENDED	138.00	12.47	
30	TOTAL		5014.00	914.46	860.70
31	Number of Substations-31				
32					
33	EMERY SUB	TRANSMISSION-ATTENDE	345.00	138.00	69.00
34	GADSBY SUB	TRANSMISSION-ATTENDE	138.00	46.00	
35	ABAJO SUB	TRANSMISSION-UNATTEN	138.00	69.00	
36	ASHLEY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
37	BARNEY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
38	BEN LOMOND SUB	TRANSMISSION-UNATTEN	345.00	230.00	138.00
39	BLACK ROCK SUB	TRANSMISSION-UNATTEN	230.00	69.00	
40	BLACKHAWK SUB	TRANSMISSION-UNATTEN	138.00	69.00	46.00

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.
30	1					1
205	4					2
40	2					3
289	7					4
60	2					5
60	2					6
8	1					7
72	3					8
114	2					9
97	2					10
164	2					11
22	1					12
340	3					13
65	2					14
835	4	1				15
97	2					16
30	1					17
180	3					18
34	4					19
100	2					20
50	2					21
600	5					22
358	4					23
1108	6	2				24
130	2					25
249	3					26
30	1					27
30	1					28
20	1					29
7124	83	3				30
						31
						32
783	13					33
318	2					34
67	1					35
133	2					36
100	1					37
1813	5					38
75	1					39
100	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	CAMERON SUB	TRANSMISSION-UNATTEN	138.00	46.00	
2	CAMP WILLIAMS SUB	TRANSMISSION-UNATTEN	345.00	138.00	12.47
3	CLOVER SUB	TRANSMISSION-UNATTEN	345.00	138.00	14.40
4	COLUMBIA SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
5	CRANER FLAT SUB	TRANSMISSION-UNATTEN	138.00	12.47	
6	CROYDON SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
7	CUTLER SUB	TRANSMISSION-UNATTEN	138.00	46.00	
8	EL MONTE SUB	TRANSMISSION-UNATTEN	138.00	46.00	
9	GARKANE SUB	TRANSMISSION-UNATTEN	69.00	46.00	
10	GREEN CANYON SUB	TRANSMISSION-UNATTEN	138.00	46.00	
11	GRINDING SUB	TRANSMISSION-UNATTEN	138.00	13.80	
12	HELPER SUB	TRANSMISSION-UNATTEN	138.00	46.00	
13	HONEYVILLE SUB	TRANSMISSION-UNATTEN	138.00	46.00	
14	HORSESHOE SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
15	HUNTINGTON SUB	TRANSMISSION-UNATTEN	345.00	138.00	24.90
16	JERUSALEM SUB	TRANSMISSION-UNATTEN	138.00	46.00	
17	LAMPO SUB	TRANSMISSION-UNATTEN	138.00	46.00	
18	MATHINGTON SUB	TRANSMISSION-UNATTEN	138.00	46.00	13.20
19	MCFADDEN SUB	TRANSMISSION-UNATTEN	138.00	46.00	
20	MIDDLETON SUB	TRANSMISSION-UNATTEN	138.00	69.00	34.50
21	MIDVALLEY SUB	TRANSMISSION-UNATTEN	345.00	138.00	
22	MIDWAY CITY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
23	MINERAL PRODUCTS SUB	TRANSMISSION-UNATTEN	69.00	46.00	
24	MOAB SUB	TRANSMISSION-UNATTEN	138.00	69.00	
25	NEBO SUB	TRANSMISSION-UNATTEN	138.00	46.00	
26	PAROWAN VALLEY SUB	TRANSMISSION-UNATTEN	230.00	138.00	34.50
27	PAVANT SUB	TRANSMISSION-UNATTEN	230.00	46.00	
28	PINTO SUB	TRANSMISSION-UNATTEN	345.00	138.00	69.00
29	RED BUTTE SUB	TRANSMISSION-UNATTEN	345.00	138.00	
30	SIGURD SUB	TRANSMISSION-UNATTEN	345.00	230.00	138.00
31	SMITHFIELD SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
32	SPANISH FORK SUB	TRANSMISSION-UNATTEN	345.00	138.00	46.00
33	ST GEORGE SUB	TRANSMISSION-UNATTEN	138.00	16.50	
34	THREE PEAKS SUB	TRANSMISSION-UNATTEN	345.00	138.00	
35	WEST CEDAR SUB	TRANSMISSION-UNATTEN	230.00	138.00	34.50
36	TOTAL		8441.00	3377.77	724.35
37	Number of Substations-43				
38					
39	WASHINGTON				
40	ATTALIA 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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
25	4					1
169	2					2
448	1					3
71	2					4
40	2					5
81	2					6
50	1					7
312	3					8
33	1					9
67	2					10
225	3					11
142	2					12
35	1					13
80	2					14
270	4					15
67	1					16
75	1					17
160	5	1				18
45	1					19
141	4					20
900	2					21
67	1					22
12	1					23
67	1					24
67	1					25
138	2					26
133	2					27
258	3					28
414	2					29
1124	6					30
63	2					31
1017	5					32
100	3	1				33
450	1					34
262	3					35
10997	106	2				36
						37
						38
						39
25	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	/ /	End of 2015/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	BOWMAN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
2	CASCADE KRAFT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	4.16
3	CLINTON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
4	DAYTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
5	DODD ROAD SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
6	GRANDVIEW SUB	DISTRIBUTION-UNATTEN	115.00	12.47	69.00
7	HOPLAND SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
8	NACHES	DISTRIBUTION-UNATTEN	115.00	12.00	
9	NOB HILL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
10	NORTH PARK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
11	ORCHARD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
12	PACIFIC SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
13	POMEROY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	PROSPECT POINT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
15	PUNKIN CENTER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
16	RIVER ROAD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
17	SELAH SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
18	SULPHUR CREEK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
19	SUNNYSIDE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
20	TIETON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	34.50
21	TOPPENISH SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
22	TOUCHET SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	VOELKER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
24	WAITSBURG SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	WAPATO SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
26	WENAS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
27	WHITE SWAN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
28	WILEY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
29	TOTAL		2921.00	369.49	107.66
30	Number of Substations-29				
31					
32	CENTRAL SUB	T/D-UNATTENDED	69.00	12.47	
33	MILL CREEK SUB	T/D-UNATTENDED	69.00	12.47	
34	UNION GAP SUB	T/D-UNATTENDED	230.00	115.00	12.47
35	TOTAL		368.00	139.94	12.47
36	Number of Substations-3				
37					
38	OUTLOOK SUB	TRANSMISSION-UNATTEN	230.00	115.00	
39	PASCO SUB	TRANSMISSION-UNATTEN	115.00	69.00	7.20
40	POMONA HEIGHTS SUB	TRANSMISSION-UNATTEN	230.00	115.00	13.20

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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
45	2					1
118	6					2
25	1					3
23	2					4
25	4					5
42	2					6
50	2					7
25	1					8
42	2					9
45	2					10
50	2					11
28	3					12
9	1					13
40	2					14
20	2					15
51	4					16
45	2					17
25	1					18
45	2					19
29	2					20
50	2					21
6	1					22
25	1					23
9	1					24
45	2					25
25	2					26
22	2					27
45	2					28
1034	59					29
						30
						31
14	1					32
45	2					33
345	4					34
404	7					35
						36
						37
125	1					38
39	9					39
325	3					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	/ /	End of 2015/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	WALLA WALLA 230KV SUB	TRANSMISSION-UNATTEN	230.00	69.00	
2	WALLULA SUB	TRANSMISSION-UNATTEN	230.00	69.00	
3	WINE COUNTRY SUB	TRANSMISSION-UNATTEN	230.00	115.00	
4	TOTAL		1265.00	552.00	20.40
5	Number of Substations-6				
6					
7	WYOMING				
8	ANTELOPE MINE SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
9	ASTLE STREET	DISTRIBUTION-UNATTEN	34.50	13.20	
10	BAILEY DOME SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
11	BAR NUNN	DISTRIBUTION-UNATTEN	116.00	13.20	
12	BAR X SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
13	BIG MUDDY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	BIG PINEY SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
15	BLACKS FORK SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
16	BRIDGER PUMP SUB	DISTRIBUTION-UNATTEN	230.00	34.50	13.20
17	BRYAN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
18	BUFFALO TOWN SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
19	BYRON SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
20	CASSA SUB	DISTRIBUTION-UNATTEN	57.00	20.80	12.47
21	CENTER STREET SUB	DISTRIBUTION-UNATTEN	115.00	4.16	
22	CHAPMAN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	CHUKAR SUB	DISTRIBUTION-UNATTEN	12.47	4.16	
24	CHURCH AND DWIGHT SUB	DISTRIBUTION-UNATTEN	34.50	0.48	
25	COKEVILLE SUB	DISTRIBUTION-UNATTEN	46.00	24.90	
26	COLUMBIA-GENEVA SUB	DISTRIBUTION-UNATTEN	230.00	13.80	
27	COMMUNITY PARK SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
28	CROOKS GAP SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
29	DEER CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	DJ COAL MINE SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
31	DOUGLAS SUB	DISTRIBUTION-UNATTEN	57.00	2.30	
32	DRY FORK SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
33	ELK BASIN SUB	DISTRIBUTION-UNATTEN	34.50	7.20	
34	EMIGRANT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
35	EVANS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
36	EVANSTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
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 PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
300	2					1
120	2					2
250	1					3
1159	18					4
						5
						6
						7
25	1					8
12	1					9
2	1					10
30	1					11
25	1					12
7	1					13
14	1					14
150	2					15
73	4					16
25	1					17
2	3					18
2	3					19
2	6					20
12	1					21
4	1					22
1	3					23
3	2					24
4	1					25
45	2					26
45	2					27
5	3					28
9	1					29
12	1					30
6	3					31
9	1					32
5	1					33
12	1					34
9	1					35
40	2					36
28	1					37
20	1					38
50	2					39
6	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	/ /	End of 2015/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	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	115.00	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	MILL IRON SUB	DISTRIBUTION-UNATTEN	34.50	13.80	
18	MILLS SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
19	MURPHY DOME SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
20	NUGGETT SUB	DISTRIBUTION-UNATTEN	69.00	7.20	
21	OPAL SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
22	ORIN SUB	DISTRIBUTION-UNATTEN	57.00	7.20	
23	ORPHA SUB	DISTRIBUTION-UNATTEN	57.00	7.20	
24	PARADISE SUB	DISTRIBUTION-UNATTEN	69.00	25.00	
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	POISON SPIDER SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
29	POLECAT SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
30	RAINBOW SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
31	RAVEN SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
32	RED BUTTE SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
33	REFINERY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
34	SAGE HILL SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
35	SHOSHONI SUB	DISTRIBUTION-UNATTEN	34.50	2.40	
36	SLATE CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	SOUTH CODY SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
38	SOUTH ELK BASIN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
39	SOUTH TRONA SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
40	SPRING CREEK SUB	DISTRIBUTION-UNATTEN	115.00	13.20	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
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
12	1					14
20	1					15
4	1					16
12	1					17
1	3					18
5	1					19
	1					20
8	1					21
1	1					22
3	3					23
30	1					24
5	1					25
20	1					26
17	9	2				27
3	1					28
1	3					29
12	1					30
200	2					31
30	1					32
45	2					33
6	1					34
2	3					35
1	1					36
14	3	1				37
2	6					38
150	2					39
28	1					40

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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	SVILAR SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
2	TEN MILE STEP DOWN SUB	DISTRIBUTION-UNATTEN	34.50	12.50	
3	TEN MILE SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
4	THERMOPOLIS TOWN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
5	THUNDER CREEK SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
6	VETERANS SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
7	WELCH SUB	DISTRIBUTION-UNATTEN	57.00	2.40	
8	WERTZ-SINCLAIR SUB	DISTRIBUTION-UNATTEN	57.00	4.16	12.50
9	WEST ADAMS SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
10	WESTVACO SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
11	WORLAND TOWN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
12	WYOPO SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
13	WYUTA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	TOTAL		7769.27	1320.03	38.17
15	Number of Substations-86				
16					
17	BUFFALO SUB	T/D-UNATTENDED	230.00	20.80	
18	ELK HORN SUB	T/D-UNATTENDED	115.00	12.47	
19	FIREHOLE SUB	T/D-UNATTENDED	230.00	34.50	
20	HILLTOP SUB	T/D-UNATTENDED	115.00	34.50	20.80
21	LABARGE SUB	T/D-UNATTENDED	69.00	24.90	
22	POINT OF ROCKS SUB	T/D-UNATTENDED	230.00	34.50	
23	RIVERTON 230 SUB	T/D-UNATTENDED	230.00	12.47	34.50
24	YELLOWCAKE SUB	T/D-UNATTENDED	230.00	34.50	
25	TOTAL		1449.00	208.64	55.30
26	Number of Substations-8				
27					
28	DAVE JOHNSTON PLANT/SUB	TRANSMISSION-ATTENDE	230.00	115.00	69.00
29	JIM BRIDGER 345KV SUB	TRANSMISSION-ATTENDE	345.00	230.00	34.50
30	NAUGHTON SUB	TRANSMISSION-ATTENDE	230.00	138.00	69.00
31	BAIROIL SUB	TRANSMISSION-UNATTEN	115.00	34.50	57.00
32	CASPER SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
33	CHAPPELL CREEK SUB	TRANSMISSION-UNATTEN	230.00	69.00	
34	CHIMNEY BUTTE SUB	TRANSMISSION-UNATTEN	230.00	69.00	
35	FOOTE CREEK WIND FARM	TRANSMISSION-UNATTEN	230.00	34.50	
36	GLENDO AUTO SUB	TRANSMISSION-UNATTEN	69.00	57.00	
37	MANSFACE SUB	TRANSMISSION-UNATTEN	230.00	34.50	
38	MIDWEST SUB	TRANSMISSION-UNATTEN	230.00	69.00	34.50
39	MINERS SUB	TRANSMISSION-UNATTEN	230.00	34.50	9.70
40	MUSTANG SUB	TRANSMISSION-UNATTEN	230.00	115.00	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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.
2	3					1
5	1					2
12	1					3
5	1					4
9	1					5
25	2					6
3	3					7
2	6					8
3	1					9
25	1					10
5	1					11
20	1	1				12
	1					13
1684	156	4				14
						15
						16
20	1					17
25	1					18
50	2					19
45	2	1				20
8	6					21
25	1					22
74	4					23
25	1					24
272	18	1				25
						26
						27
336	4					28
703	7					29
661	4					30
53	3					31
575	4					32
67	1					33
75	1					34
196	2					35
15	2					36
20	1					37
157	3					38
20	1					39
100	1					40

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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	OREGON BASIN SUB	TRANSMISSION-UNATTEN	230.00	34.50	69.00
2	PLATTE SUB	TRANSMISSION-UNATTEN	230.00	115.00	34.50
3	RAILROAD SUB	TRANSMISSION-UNATTEN	230.00	138.00	
4	ROCK SPRINGS 230 SUB	TRANSMISSION-UNATTEN	230.00	34.50	
5	SAGE SUB	TRANSMISSION-UNATTEN	69.00	46.00	
6	THERMOPOLIS SUB	TRANSMISSION-UNATTEN	230.00	115.00	
7	TOTAL		4048.00	1598.00	446.20
8	Number of Substations-19				
9					
10	CALIFORNIA				
11	Distribution - 42				
12	T/D - 2				
13	Transmission - 6				
14					
15	IDAHO				
16	Distribution - 65				
17	T/D - 5				
18	Transmission - 17				
19					
20	MONTANA				
21	Transmission - 3				
22					
23	OREGON				
24	Distribution - 180				
25	T/D - 12				
26	Transmission - 28				
27					
28	UTAH				
29	Distribution - 280				
30	T/D - 31				
31	Transmission - 43				
32					
33	WASHINGTON				
34	Distribution - 29				
35	T/D - 3				
36	Transmission - 6				
37					
38	WYOMING				
39	Distribution - 86				
40	T/D - 8				

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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
65	2					1
140	3					2
400	1					3
50	2					4
23	1					5
175	2					6
3831	45					7
						8
						9
						10
323						11
130						12
762						13
						14
						15
736						16
344						17
5276						18
						19
						20
200						21
						22
						23
4609						24
1310						25
7511						26
						27
						28
5578						29
7124						30
10997						31
						32
						33
1034						34
404						35
1159						36
						37
						38
1684						39
272						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	/ /	End of 2015/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	Transmission - 19				
2					
3	ALL STATES				
4	Distribution - 682				
5	T/D - 61				
6	Transmission - 122				
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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32					
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36					
37					
38					
39					
40					

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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.
3831						1
						2
						3
13964						4
9584						5
29736						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
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						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Schedule Page: 426.3 Line No.: 19 Column: a

The Antelope 230kV, 161kV and 138kV Substation is jointly owned by PacifiCorp and Idaho Power Company. Ownership and operations and maintenance costs vary by type of asset as defined in the Joint Ownership and Operating Agreement.

Schedule Page: 426.3 Line No.: 21 Column: a

The Big Grassy 161kV Substation is jointly owned by PacifiCorp and Idaho Power Company. Ownership and operations and maintenance costs vary by type of asset as defined in the Joint Ownership and Operating Agreement.

Schedule Page: 426.3 Line No.: 26 Column: a

The Goshen 345kV and 161kV Substation is jointly owned by PacifiCorp and Idaho Power Company. Ownership and operations and maintenance costs vary by type of asset as defined in the Joint Ownership and Operating Agreement.

Schedule Page: 426.3 Line No.: 28 Column: a

The Jefferson 161kV Substation is jointly owned by PacifiCorp and Idaho Power Company. Ownership and operations and maintenance costs vary by type of asset as defined in the Joint Ownership and Operating Agreement.

Schedule Page: 426.3 Line No.: 29 Column: a

The Midpoint 500kV Substation is jointly owned by PacifiCorp and Idaho Power Company. Ownership and operations and maintenance costs vary by type of asset as defined in the Joint Ownership and Operating Agreement.

Schedule Page: 426.3 Line No.: 33 Column: a

The Threemile Knoll 345kV Substation is jointly owned by PacifiCorp and Idaho Power Company. Ownership and operations and maintenance costs vary by type of asset as defined in the Joint Ownership and Operating Agreement.

Schedule Page: 426.3 Line No.: 39 Column: a

The Broadview 500kV Substation is jointly owned by PacifiCorp, NorthWestern Energy, Puget Sound Energy, Inc., Portland General Electric Company and Avista Corporation. Ownership and operations and maintenance costs vary by type of asset as defined in the Transmission Agreement.

Schedule Page: 426.3 Line No.: 40 Column: a

The Colstrip 500kV and 230kV Substation is jointly owned by PacifiCorp, NorthWestern Energy, Puget Sound Energy, Inc., Portland General Electric Company and Avista Corporation. Ownership and operations and maintenance costs vary by type of asset as defined in the Transmission Agreement.

Schedule Page: 426.9 Line No.: 11 Column: a

The Dixonville 500kV Substation is jointly owned by PacifiCorp and Bonneville Power Administration ("BPA"). Ownership of the substation is as follows: PacifiCorp 50.0% and BPA 50.0%. Operation and maintenance costs are shared between the two parties and responsibility is as follows: PacifiCorp 58.0% and BPA 42.0%.

Schedule Page: 426.9 Line No.: 16 Column: a

The Hurricane 230kV Substation is jointly owned by PacifiCorp and Idaho Power Company. Ownership and operations and maintenance costs vary by type of asset as defined in the Joint Ownership and Operating Agreement.

Schedule Page: 426.9 Line No.: 21 Column: a

The Malin 500kV Substation is jointly owned by PacifiCorp, Portland General Electric ("PGE"), BPA and Western Area Power Administration ("WAPA"). Ownership of the substation is as follows: PacifiCorp 25.0%, PGE 25.0%, BPA 25.0% and WAPA 25.0%. Operation and maintenance costs are shared among the four parties and responsibility is as follows: PacifiCorp 25.0%, PGE 25.0%, BPA 25.0% and WAPA 25.0%.

Schedule Page: 426.9 Line No.: 22 Column: a

The Meridian 500kV Substation is jointly owned by PacifiCorp and BPA. Ownership of the substation is as follows: PacifiCorp 50.0% and BPA 50.0%. Operation and maintenance costs are shared between the two parties and responsibility is as follows: PacifiCorp 58.0% and BPA 42.0%.

Schedule Page: 426.20 Line No.: 1 Column: a

The Walla Walla 230kV Substation is jointly owned by PacifiCorp and Idaho Power Company. Ownership and operations and maintenance costs vary by type of asset as defined in the Joint Ownership and Operating Agreement.

Schedule Page: 426.22 Line No.: 28 Column: a

The Dave Johnston 230kV Substation is jointly owned by PacifiCorp and Black Hills Power. Ownership of the substation is as follows: PacifiCorp 85.0% and Black Hills Power 15.0%. Operation and maintenance costs are shared between the two parties based on a fixed amount derived as a factor of the percentage owned of the original installed substation.

Schedule Page: 426.22 Line No.: 29 Column: a

The Jim Bridger 345kV Substation is jointly owned by PacifiCorp and Idaho Power Company. Ownership and operations and maintenance costs vary by type of asset as defined in the Joint Ownership and Operating Agreement.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Coal purchases / support services / construction			
3	and maintenance / equipment rental	Bridger Coal Company		185,697,769
4				
5	Deer Creek coal mine closure/decommissioning			
6	services and coal mining services	Energy West Mining Company	151, 182.3	18,430,819
7				
8	Coal purchases	Trapper Mining Inc.	151	15,484,422
9				
10	Administrative support services	Interwest Mining Company		1,068,243
11				
12	Administrative services under the IASA	BHE		4,737,182
13	Administrative services under the IASA	MEC		4,871,181
14	Administrative services under the IASA	Kern River Gas Transmission Company	107, 426.5, 923	64,298
15				
16	Gas transportation services	Kern River Gas Transmission Company	547	3,085,186
17				
18	Employee relocation services	HomeServices of America, Inc.		1,759,354
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Proceeds from sale of mining equipment and			
22	information technology and administrative			
23	support services	Bridger Coal Company		18,113,622
24				
25	Financial support services and employee benefits	Interwest Mining Company	557	475,819
26				
27	Joint use services	Charter Communications, Inc.		1,079,992
28				
29	Administrative services under the IASA	BHE		457,681
30	Administrative services under the IASA	MEC		2,215,513
31	Administrative services under the IASA	HomeServices of America, Inc.	920, 921	266,330
32	Administrative services under the IASA	Northern Natural Gas Company		325,088
33	Administrative services under the IASA	BHE U.S. Transmission, LLC		1,648,557
34	Administrative services under the IASA	MTL Canyon Holdings, LLC	560, 920, 921	305,137
35	Administrative services under the IASA	MCCT	920, 921	369,922
36				
37				
38				
39				
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Rail services / right-of-way fees	BNSF Railway Company	151,507,567,589	39,485,617

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3				
4	Banking services and financial transactions			
5	related to energy hedging activity	Wells Fargo & Company		7,002,152
6				
7	Banking services	U.S. Bancorp		568,431
8				
9	Computer hardware and software and computer			
10	systems maintenance and support services	International Business Machines Corp	165,909,921,935	1,957,304
11				
12	Rating agency fees	Moody's Investors Service	181, 186, 930.2	314,111
13				
14	Surety bond premium	National Indemnity Company	165	427,920
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2				
3				
4				

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Schedule Page: 429 Line No.: 3 Column: c

Accounts charged for Bridger Coal Company: 107, 108, 151, 501 and 514.

Schedule Page: 429 Line No.: 3 Column: d

Non-power goods or services provided by Bridger Coal Company are as follows:

Coal purchases	$185,643,100
Support services, construction and maintenance and equipment rental	54,669
	$185,697,769

Schedule Page: 429 Line No.: 6 Column: d

Non-power goods or services provided by Energy West Mining Company are as follows:

Deer Creek coal mine closure/decommissioning services	$17,648,065
Coal mining services	782,754
	$18,430,819

Under the terms of the coal mining agreement between PacifiCorp and Energy West Mining Company, Energy West Mining Company provided coal mining services to PacifiCorp that are absorbed directly by PacifiCorp.

Schedule Page: 429 Line No.: 10 Column: c

Accounts charged for Interwest Mining Company: 421, 426.5, 557 and 928.

Schedule Page: 429 Line No.: 10 Column: d

Interwest Mining Company manages PacifiCorp's mining operations and charges management services to Bridger Coal Company and Energy West Mining Company. Interwest Mining Company also charges PacifiCorp for administrative support services. All costs incurred by Interwest Mining Company are absorbed by PacifiCorp, Bridger Coal Company and Energy West Mining Company.

Schedule Page: 429 Line No.: 12 Column: a

This footnote applies to all occurrences of "Administrative services under the IASA" on page 429. "IASA" is the Intercompany Administrative Services Agreement between Berkshire Hathaway Energy Company ("BHE") and its subsidiaries. Amounts which are chargeable to or from another affiliate are assigned first by coding to the specific affiliate. These charges are based on actual labor, benefits and operational costs incurred. Amounts not directly assignable to an individual affiliate, such as work performed where multiple affiliates benefit, are assigned on the basis of allocations, as described below:

Labor and Assets: An equal weighting of each company's labor and assets expressed as a percentage of the whole ((labor % + assets %) ÷ 2) determines the portion assigned to each company. Labor is 12 months ended through December of the prior year. Assets are total assets at December 31 of the prior year. Nine combinations of this allocator are used for allocating services that benefit different companies within the BHE organization.

Legislative and Regulatory: The Legislative and Regulatory allocation is used to allocate costs incurred by BHE's legislative & regulatory groups. The legislative & regulatory groups work on a variety of legislative and regulatory subject matter for a select group of companies within the BHE organization. The Legislative and Regulatory allocation percentages are based on the legislative & regulatory groups' estimation of the time and resources spent on these selected companies.

Information Technology Infrastructure: Allocates costs related to shared information technology infrastructure owned by the affiliate to other benefited affiliates based on an aggregation of various measures of usage of such infrastructure including storage capacity utilized, number of servers utilized, server processing times, etc.

Plant: This allocator distributes costs of managing the corporate insurance function based on assets for each affiliate.

Schedule Page: 429 Line No.: 12 Column: c

Accounts charged for BHE: 426.4, 426.5 and 923.

Schedule Page: 429 Line No.: 12 Column: d

Excluded from this line are "convenience" payments made to vendors by one entity on behalf of, and charged to, other entities within the BHE group. Such affiliate charges reflect the ability to obtain price discounts as a result of larger purchasing power.

Excluded from this page are reimbursements by BHE for payments made by PacifiCorp to its employees under the long-term incentive plan ("LTIP") that was maintained by BHE upon vesting of the awards. Also excluded from this page are reimbursements of payments related to wages and benefits associated with transferred employees.

The convenience payments, the LTIP reimbursements and the reimbursements associated with transferred employees do not constitute "services" as required by this page.

Schedule Page: 429 Line No.: 13 Column: b

This footnote applies to all occurrences of “MEC” on page 429. Complete name is MidAmerican Energy Company.

Schedule Page: 429 Line No.: 13 Column: c

Accounts charged for MEC: 107, 143, 146, 426.4, 426.5, 921 and 923.

Schedule Page: 429 Line No.: 13 Column: d

Excluded from this line are "convenience" payments made to vendors by one entity on behalf of, and charged to, other entities within the BHE group. Such affiliate charges reflect the ability to obtain price discounts as a result of larger purchasing power and do not constitute "services" as required by this page.

Schedule Page: 429 Line No.: 14 Column: d

Excluded from this line are "convenience" payments made to vendors by one entity on behalf of, and charged to, other entities within the BHE group. Such affiliate charges reflect the ability to obtain price discounts as a result of larger purchasing power and do not constitute "services" as required by this page.

Schedule Page: 429 Line No.: 18 Column: c

Accounts charged for HomeServices of America, Inc.: 184, 501, 502, 506, 535, 539, 548, 549, 553, 557, 560, 561.2, 580, 581, 590, 592, 593, 901, 902, 903, 908 and 921.

Schedule Page: 429 Line No.: 23 Column: c

Accounts charged for Bridger Coal Company: 107, 182.3, 501, 557, 909, 920 and 921.

Schedule Page: 429 Line No.: 23 Column: d

Non-power goods or services provided to Bridger Coal Company are as follows:

Proceeds from sale of mining equipment	$17,741,467
Information technology and administrative support	372,155
	$18,113,622

Schedule Page: 429 Line No.: 25 Column: d

PacifiCorp provides Interwest Mining Company with financial support services as well as employee benefits for Interwest Mining Company's employees. These costs are charged to Interwest Mining Company and are included in the management services that Interwest Mining Company provides to Bridger Coal Company and Energy West Mining Company.

Schedule Page: 429 Line No.: 27 Column: c

Accounts charged for Charter Communications, Inc.: 253, 454, 593 and 929.

Schedule Page: 429 Line No.: 29 Column: c

Accounts charged for BHE: 426.5, 557, 560, 920 and 921.

Schedule Page: 429 Line No.: 29 Column: d

Excluded from this line are "convenience" payments made to vendors by one entity on behalf of, and charged to, other entities within the BHE group. Such affiliate charges reflect the ability to obtain price discounts as a result of larger purchasing power and do not constitute "services" as required by this page.

Schedule Page: 429 Line No.: 30 Column: c

Accounts charged for MEC: 426.5, 506, 549, 556, 557, 580, 588, 920 and 921.

Schedule Page: 429 Line No.: 30 Column: d

Excluded from this line are "convenience" payments made to vendors by one entity on behalf of, and charged to, other entities within the BHE group. Such affiliate charges reflect the ability to obtain price discounts as a result of larger purchasing power and do not constitute "services" as required by this page.

Schedule Page: 429 Line No.: 31 Column: d

Excluded from this line are "convenience" payments made to vendors by one entity on behalf of, and charged to, other entities within the BHE group. Such affiliate charges reflect the ability to obtain price discounts as a result of larger purchasing power and do not constitute "services" as required by this page.

Schedule Page: 429 Line No.: 32 Column: c

Accounts charged for Northern Natural Gas Company: 426.5, 557, 920 and 921.

Schedule Page: 429 Line No.: 32 Column: d

Excluded from this line are "convenience" payments made to vendors by one entity on behalf of, and charged to, other entities within the BHE group. Such affiliate charges reflect the ability to obtain price discounts as a result of larger purchasing power and do not constitute "services" as required by this page.

Schedule Page: 429 Line No.: 33 Column: c

Accounts charged for BHE U.S. Transmission, LLC: 426.5, 557, 560, 580, 920 and 921.

Schedule Page: 429 Line No.: 33 Column: d

Excluded from this line are "convenience" payments made to vendors by one entity on behalf of, and charged to, other entities within the BHE group. Such affiliate charges reflect the ability to obtain price discounts as a result of larger purchasing power and do not constitute "services" as required by this page.

Schedule Page: 429 Line No.: 34 Column: d

Excluded from this line are "convenience" payments made to vendors by one entity on behalf of, and charged to, other entities within the BHE group. Such affiliate charges reflect the ability to obtain price discounts as a result of larger purchasing power and do not constitute "services" as required by this page.

Schedule Page: 429 Line No.: 35 Column: b

Complete name is MidAmerican Central California Transco, LLC.

Schedule Page: 429 Line No.: 35 Column: d

Excluded from this line are "convenience" payments made to vendors by one entity on behalf of, and charged to, other entities within the BHE group. Such affiliate charges reflect the ability to obtain price discounts as a result of larger purchasing power and do not constitute "services" as required by this page.

Schedule Page: 429.1 Line No.: 2 Column: d

Non-power goods or services provided by BNSF Railway Company are as follows:

Rail services	$39,428,357
Right-of-way fees	57,260
	$39,485,617

Included in the rail services are amounts related to a jointly-owned plant that are paid indirectly to BNSF Railway Company.

Schedule Page: 429.1 Line No.: 5 Column: c

Accounts charged for Wells Fargo & Company: 228.3, 419, 426.5, 427, 431, 501, 547, 560, 588, 903, 921 and 928.

Schedule Page: 429.1 Line No.: 5 Column: d

Non-power goods or services provided by Wells Fargo & Company are as follows:

Banking services	$1,362,102
Financial transactions related to energy hedging activity	5,640,050
	$7,002,152

Schedule Page: 429.1 Line No.: 7 Column: c

Accounts charged for U.S. Bancorp: 419, 427, 431, 537, 557, 903, 920, 928 and 930.2.

Schedule Page: 429.1 Line No.: 10 Column: b

Complete name is International Business Machines Corporation.

Schedule | Page No.

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