PAC-E

ROCKY MOUNTAIN
POWER
A DIVISION OF PACIFICORP

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

RECEIVED
2017 MAY 23 AM 9:20
IDAHO PUBLIC
UTILITIES COMMISSION

May 23, 2017

VIA OVERNIGHT DELIVERY

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

Attention: Diane Hanian
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, 2016. An electronic copy of the report is provided on the enclosed CD for your convenience.

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

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

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

Exact Legal Name of Respondent (Company)	Year/Period of Report
PacifiCorp	End of 2016/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/forms/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/forms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/forms.asp#3Q-gas .

IV. When to Submit:

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

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

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

V. Where to Send Comments on Public Reporting Burden.

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

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

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

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

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

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

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

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

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

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

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

General Penalties

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

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

IDENTIFICATION

01 Exact Legal Name of Respondent	02 Year/Period of Report
PacifiCorp	End of 2016/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	06 Title of Contact Person
Mark Staehnke	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*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(503) 813-5784	(1) ☒ An Original (2) ☐ A Resubmission	/ /

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Nikki L. Kobliha	Nikki L. Kobliha	04/14/2017
02 Title: Vice President, CFO and Treasurer		

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 2016/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	NA
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	NA
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	NA
25	Unrecovered Plant and Regulatory Study Costs	230	NA
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".

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 2016/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, Chief Financial Officer and Treasurer
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 selling electricity. In addition to retail sales, PacifiCorp buys and sells 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.

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 90.0%, Walter Scott, Jr. (along with family members and related entities) owns 9.0% and Gregory E. Abel owns 1.0% of BHE's common stock.

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 ceased mining operations in 2015.

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. Three of the PacifiCorp Foundation's five 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 2016/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	338,000
4	President and Chief Executive Officer,		
5	Rocky Mountain Power	Cindy A. Crane	338,000
6	Vice President, Chief Financial Officer and Treasurer	Nikki L. Kobliha	203,900
7	President and Chief Executive Officer,		
8	PacifiCorp Transmission	R. Patrick Reiten	344,007
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Schedule Page: 104 Line No.: 1 Column: c

PacifiCorp sets forth the salary information for its "named executive officers" for the year ended December 31, 2016, consistent with Item 402 of Regulation S-K promulgated by the Securities and Exchange Commission, in its 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. Refer to BHE’s Annual Report on Form 10-K for the year ended December 31, 2016, for executive compensation information for Mr. Abel.

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

R. Patrick Reiten, President and Chief Executive Officer of PacifiCorp Transmission, resigned as a director and officer of PacifiCorp effective December 31, 2016. For further information, 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 2016/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, 2016:	
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 Street, 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	Douglas L. Anderson	1111 South 103rd Street, Omaha, Nebraska 68124
9	Patrick J. Goodman	666 Grand Avenue, 29th Floor, Des Moines, Iowa 50309
10	Natalie L. Hocken	825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232
11	Andrea L. Kelly	1800 M Street NW, Suite 300, Washington, DC 20036
12	R. Patrick Reiten	1800 M Street NW, Suite 300, Washington, DC 20036
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Schedule Page: 105 Line No.: 11 Column: a

Andrea L. Kelly, Senior Vice President, Legislative and Regulatory Strategy of Berkshire Hathaway Energy Company, resigned as a director of PacifiCorp effective December 31, 2016. For further information, refer to Item 13 in Important Changes During the Year in this Form No. 1.

Schedule Page: 105 Line No.: 12 Column: a

R. Patrick Reiten, President and Chief Executive Officer of PacifiCorp Transmission, resigned as a director and officer of PacifiCorp effective December 31, 2016. For further information, 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 2016/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 2016/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	20160318-5009	03/18/2016	ER16-1231		
2	20160516-5287	05/16/2016	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 2016) to be effective 6/01/2016 in FERC Docket ER16-1231

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

Transmission Formula Rate Annual Update Informational Filing of PacifiCorp in FERC Docket ER11-3643

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

PacifiCorp's Volume No. 11 Open Access Transmission Tariff

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 2016/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)			
Bancroft	09/20/2016	09/20/2026	—
Newdale	11/01/2016	11/01/2031	—
Lava Hot Springs	08/09/2016	08/09/2036	—
Oregon(3)			
Canyonville	10/27/2016	10/27/2021	5.0%
Joseph	06/03/2016	06/03/2036	3.5%
Powers	01/08/2016	12/31/2025	5.0%
Roseburg	07/01/2016	07/01/2026	9.0%
Winston	08/01/2016	08/01/2026	7.0%
Utah(4)			
Amalga	06/08/2016	06/08/2026	—
Bear River	04/14/2016	04/14/2021	—
Box Elder County	09/28/2016	09/28/2026	—
Cache County	05/04/2016	05/04/2026	—
Centerville	10/25/2016	12/31/2021	—
Clarkston	01/11/2016	01/11/2031	—
Fielding	10/18/2016	10/18/2026	—
Glenwood	02/15/2016	02/15/2026	—
Helper	09/28/2016	09/28/2026	—
Honeyville	01/11/2016	01/11/2026	—
Marysvale	11/21/2016	11/21/2036	—
Mendon	05/24/2016	05/24/2026	—
Newton	11/01/2016	11/01/2031	—
North Salt Lake	06/30/2016	06/30/2021	—
Ogden	01/01/2016	01/01/2041	—
Salt Lake City	12/01/2016	12/01/2021	—
Sandy	02/05/2016	02/05/2026	—
Springdale	10/12/2016	03/31/2017	—
Utah County	05/04/2016	05/04/2066	—
Washington County	05/24/2016	05/24/2036	—
West Haven	04/29/2016	04/29/2026	—
Washington(4)			
None			
Wyoming(5)			
Frannie	12/07/2016	12/07/2041	4.0%
Hudson	10/25/2016	10/25/2033	4.0%
Lovell	05/03/2016	05/03/2041	2.0%

(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 December 2016, PacifiCorp finalized an agreement with the Navajo Nation Council and President of the Navajo Nation for the sale of certain facilities located in San Juan County, Utah to the Navajo Tribal Utility Authority ("NTUA"). As a result, PacifiCorp transferred assets, substantially consisting of distribution facilities, serving approximately 1,200 customers on the Navajo Nation Reservation to the NTUA. PacifiCorp filed with the Utah Public Service Commission ("UPSC"), Wyoming Public Service Commission ("WPSC") and Oregon Public Utility Commission ("OPUC") to approve the sale of certain facilities, including a power supply agreement with the NTUA for PacifiCorp to sell power to the NTUA, effective after the close of the sale and commission approval. Subsequently, PacifiCorp recorded the sale in Account 102, Electric plant purchased or sold. In April 2017, PacifiCorp filed with the Federal Energy Regulatory Commission ("FERC") to approve the journal entries required by the Uniform System of Accounts in Docket No. AC17-85-000. Commission authorizations and notifications are as follows:

- WPSC – Docket No. 20000-487-EA-15, August 2016.
- OPUC – Docket No. UP 337, Order No. 16-241, July 2016.
- UPSC – Docket No. 15-035-84, June 2016.
- Idaho Public Utilities Commission ("IPUC") – Advisory Letter to Case No. PAC-E-15-17, January 2016.

In October 2016, PacifiCorp consummated the exchange of certain transmission facilities with Western Area Power Administration ("WAPA"), in which PacifiCorp acquired from WAPA certain 230kV transmission assets located at the Thermopolis Substation in Wyoming in exchange for selling to WAPA certain 230kV transmission assets located at the Spence Substation in Wyoming. Commission authorizations and notifications are as follows:

- OPUC – Docket No. UP 342, Order No. 16-328, August 2016.
- WPSC – Docket No. 20000-496-EA-16, August 2016.
- California Public Utilities Commission ("CPUC") – Advice Letter 542-E, July 2016.
- FERC – Docket No. EC16-113-000, May 2016.

In April 2016, PacifiCorp acquired certain 46kV transmission facilities located in or near Fillmore, Utah and associated electric plant from Flowell Electric Association, Inc. and recorded the transaction in Account 102, Electric plant purchased or sold. In August 2016, the FERC approved the journal entries required by the Uniform System of Accounts in Docket No. AC16-151-000 as filed by PacifiCorp in July 2016. Accordingly, PacifiCorp cleared Account 102, Electric plant purchased or sold and recorded the acquisition to the appropriate accounts. Commission authorization is as follows:

- FERC – Docket No. EC16-57-000, February 2016.

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 May 2016, the FERC approved the journal entries required by the Uniform System of Accounts in Docket No. AC16-46-000 as filed by PacifiCorp in February 2016. Accordingly, PacifiCorp cleared Account 102, Electric plant purchased or sold and recorded the sale to the appropriate accounts. Commission authorizations are as follows:

- WPSC – Docket No. 20000-475-EA-15, September 2015.
- OPUC – Docket No. UP 325, Order No. 15-151, 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. Subsequently, PacifiCorp recorded the exchange in Account 102, Electric plant purchased or sold. In September 2016, the FERC approved the journal entries required by the Uniform System of Accounts in Docket No. AC16-104-000 as filed by PacifiCorp in April 2016 and supplemented in July 2016. Accordingly, PacifiCorp cleared Account 102, Electric plant purchased or sold and recorded the exchange to the appropriate accounts. Commission authorizations and notifications are as follows:

- UPSC – Docket No. 14-035-150, October 2015.
- Washington Utilities and Transportation Commission ("WUTC") – Docket No. UE-144136, September 2015.
- CPUC – Decision 15-08-037, Application 14-12-022, August 2015.
- WPSC – Docket No. 20000-465-EA-14, August 2015.
- FERC – Docket No. EC15-54-000, ER15-680-000 and ER15-681-000, June 2015.
- IPUC – Case No. PAC-E-14-11, Order No. 33313, June 2015.
- OPUC – Docket No. UP 315, Order No. 15-184, June 2015.

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 December 2016, the FERC approved the journal entries required by the Uniform System of Accounts in Docket No. AC15-163-000 as filed by PacifiCorp in July 2015 and supplemented in April 2016. Accordingly, PacifiCorp cleared Account 102, Electric plant purchased or sold and recorded the sale to the appropriate accounts. Commission authorizations and notifications are as follows:

- OPUC – Docket No. UP 312, Order No. 15-071, March 2015.
- WPSC – Docket No. 20000-459-EA-14, January 2015.
- IPUC – Notification letter, November 2014.

ITEM 4.

None.

ITEM 5.

In April 2017, PacifiCorp filed its 2017 Integrated Resource Plan ("IRP") with state commissions. The IRP includes investments in renewable energy resources, upgrades to PacifiCorp’s existing wind fleet and energy efficiency measures to meet future customer needs. The $3.5 billion plan set to be in place by 2020, also incorporates building an additional transmission line segment to facilitate the expansion of wind generation.

In December 2016, PacifiCorp finalized an agreement with the Navajo Council and President of the Navajo Nation for the sale of certain facilities located in San Juan County, Utah to the Navajo Tribal Utility Authority. As a result, PacifiCorp transferred approximately 30 miles of transmission lines, along with distribution lines and four substations, serving approximately 1,200 customers on the Navajo Nation Reservation.

Refer to pages 424-425, Transmission lines added or altered during the year, in this Form No. 1 for additional information regarding transmission lines added or removed during the year ended December 31, 2016.

ITEM 6.

Short-term Debt and Credit Facilities

Regulatory authorities limit PacifiCorp to $1.5 billion of short-term debt. As of December 31, 2016, PacifiCorp had $270 million of short-term debt outstanding at a weighted average interest rate of 0.96%.

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:

- 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.
- OPUC – Docket No. UF-4120, Order No. 98-158, dated April 16, 1998.
- WUTC – Docket No. UE-980404, dated April 8, 1998.

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

Long-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 future issuances are as follows:

- IPUC – Case No. PAC-E-14-05, Order No. 33083, dated July 29, 2014, effective through June 30, 2019.
- OPUC – Docket No. UF-4288, Order No. 14-268, dated July 22, 2014.

As of December 31, 2016, PacifiCorp had $255 million of letters of credit providing credit enhancement and liquidity support for variable-rate tax-exempt bond obligations totaling $251 million plus interest. These letters of credit were fully available as of December 31, 2016 and expire periodically through March 2019. For further discussion, refer to Note 6 of Notes to Financial Statements in this Form No. 1.

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, 2016, PacifiCorp estimated it would be able to issue up to $9.7 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, 2016, PacifiCorp's bargaining unit wage scale changes were as follows:

Unions Represented	% Increase (1)	Effective Date(s)	Estimated Annual Financial Impact (2)
IBEW 57 Combustion Turbine (UT)	1.87%	01/26/2016	$ 55,112
IBEW 57 Laramie (WY)	1.03%	06/26/2016	5,617
IBEW 57 Power Delivery (UT, ID & WY)	1.84%	01/26/2016	1,428,626
IBEW 57 Power Supply (UT, ID & WY)	1.87%	01/26/2016	686,990
IBEW 125 (OR, WA)	1.90%	01/26/2016	478,574
IBEW 659 (OR, CA)	1.37%	04/26/2016	436,584
UWUA 127 (WY)	0.53%	09/26/2016	239,645
UWUA 197 (OR)	1.21%	05/26/2016	17,936
Total			$ 3,349,084

(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.

Subsequent to December 31, 2016, PacifiCorp received $1.7 million in dividends from Fossil Rock Fuels, LLC, a wholly owned subsidiary of PacifiCorp, as of April 3, 2017.

For the year ended December 31, 2016, Pacific Minerals, Inc., a wholly owned subsidiary of PacifiCorp, declared and paid dividends of $55 million to PacifiCorp. In addition, Fossil Rock Fuels, LLC, a wholly owned subsidiary of PacifiCorp, declared and paid dividends of $3.4 million consisting of $1.4 million unappropriated retained earnings distribution and $2.0 million return of capital 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, 2016, other than preferred and common stock dividends declared and paid.

ITEM 11.

(Reserved.)

ITEM 12.

None.

ITEM 13.

Nikki L. Kobliha, Vice President and Chief Financial Officer was elected as a director of PacifiCorp and appointed as PacifiCorp's Treasurer effective February 1, 2017.

Douglas L. Anderson, Chief Corporate Counsel of Berkshire Hathaway Energy Company, resigned as a director of PacifiCorp effective January 13, 2017.

Andrea L. Kelly, Senior Vice President, Legislative and Regulatory Strategy of Berkshire Hathaway Energy Company, resigned as a director of PacifiCorp effective December 31, 2016.

R. Patrick Reiten, President and Chief Executive Officer of PacifiCorp Transmission, resigned as a director and officer of PacifiCorp effective December 31, 2016 and was appointed Senior Vice President of Government Relations for Berkshire Hathaway Energy Company effective January 1, 2017.

ITEM 14.

Not applicable.

Deloitte.

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USA

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www.deloitte.com

INDEPENDENT AUDITORS' REPORT

PacifiCorp
Portland, Oregon

We have audited the accompanying financial statements of PacifiCorp (the "Company"), which comprise the balance sheet—regulatory basis as of December 31, 2016, and the related statements of income—regulatory basis, retained earnings—regulatory basis, and cash flows—regulatory basis for the year then ended, included on pages 110 through 123 of the accompanying Federal Energy Regulatory Commission Form 1, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the regulatory-basis financial statements referred to above present fairly, in all material respects, the assets, liabilities, and proprietary capital of PacifiCorp as of December 31, 2016, and the results of its operations and its cash flows for the year then ended in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

Basis of Accounting

As discussed in Note 2 to the financial statements, these financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a basis of accounting other than accounting principles generally accepted in the United States of America. Our opinion is not modified with respect to this matter.

Restricted Use

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

Deloitte & Touche LLP

April 14, 2017

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 2016/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	27,271,434,702	26,729,137,536
3	Construction Work in Progress (107)	200-201	655,882,614	628,213,113
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		27,927,317,316	27,357,350,649
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	9,693,954,266	9,237,522,532
6	Net Utility Plant (Enter Total of line 4 less 5)		18,233,363,050	18,119,828,117
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)		18,233,363,050	18,119,828,117
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		13,733,068	13,824,869
19	(Less) Accum. Prov. for Depr. and Amort. (122)		2,987,502	3,032,392
20	Investments in Associated Companies (123)		69,928	69,928
21	Investment in Subsidiary Companies (123.1)	224-225	200,451,214	241,143,969
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)		99,989,115	89,802,688
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		6,428,837	15,562,725
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		2,153,282	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		319,837,942	357,371,787
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		14,877,880	5,873,910
36	Special Deposits (132-134)		8,880,097	0
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		32,867	33,910
39	Notes Receivable (141)		2,458,965	10,055,988
40	Customer Accounts Receivable (142)		388,665,430	400,806,409
41	Other Accounts Receivable (143)		43,345,202	42,519,736
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		7,116,112	7,006,495
43	Notes Receivable from Associated Companies (145)		1,673,326	0
44	Accounts Receivable from Assoc. Companies (146)		24,733,333	23,759,933
45	Fuel Stock (151)	227	214,693,832	192,305,988
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	228,261,286	233,132,093
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		65,837,449	57,531,155
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		1,658,607	1,485,898
61	Accrued Utility Revenues (173)		274,945,000	244,424,000
62	Miscellaneous Current and Accrued Assets (174)		0	131,614
63	Derivative Instrument Assets (175)		20,541,832	8,433,083
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		2,153,282	0
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		1,281,335,712	1,213,487,222
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		29,888,534	33,071,963
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	1,538,109,950	1,679,069,828
73	Prelim. Survey and Investigation Charges (Electric) (183)		978,052	973,951
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)		-21,901	23,727
78	Miscellaneous Deferred Debits (186)	233	61,472,266	70,244,403
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)		5,779,388	6,351,794
82	Accumulated Deferred Income Taxes (190)	234	541,859,343	606,211,204
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,178,065,632	2,395,946,870
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		22,012,602,336	22,086,633,996

Schedule Page: 110 Line No.: 43 Column: c

Represents amounts due from Pacific Minerals, Inc., a wholly owned subsidiary of PacifiCorp, pursuant to an umbrella loan agreement for which the interest rate is determined daily and is equal to the lowest cost of short-term borrowings PacifiCorp could otherwise incur externally. At December 31, 2016, the interest rate on the outstanding loan balance was 0.96%.

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

As of December 31, 2016, Account 146, Accounts receivable from associated companies, included $18,474,407 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, 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.: 77 Column: c

The credit balance represents a timing difference between work incurred and advances received from customers.

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 2016/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	3,417,945,896	3,417,945,896
3	Preferred Stock Issued (204)	250-251	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	2,803,600,023	2,877,592,434
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	116,946,442	155,605,539
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)	-12,594,198	-12,014,638
16	Total Proprietary Capital (lines 2 through 15)		7,389,258,658	7,502,489,726
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	7,093,197,000	7,159,339,000
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)		58,074	69,100
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		11,483,368	12,502,206
24	Total Long-Term Debt (lines 18 through 23)		7,081,771,706	7,146,905,894
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		21,090,034	30,062,429
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		-1,507,842	26,550,966
29	Accumulated Provision for Pensions and Benefits (228.3)		364,084,317	336,117,800
30	Accumulated Miscellaneous Operating Provisions (228.4)		36,933,054	37,102,444
31	Accumulated Provision for Rate Refunds (229)		0	58,173
32	Long-Term Portion of Derivative Instrument Liabilities		25,100,250	32,083,864
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		214,786,003	224,250,680
35	Total Other Noncurrent Liabilities (lines 26 through 34)		660,485,816	686,226,356
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		270,000,000	20,000,000
38	Accounts Payable (232)		377,797,383	445,603,914
39	Notes Payable to Associated Companies (233)		0	15,242,674
40	Accounts Payable to Associated Companies (234)		148,165,802	140,098,106
41	Customer Deposits (235)		45,984,008	45,700,120
42	Taxes Accrued (236)	262-263	42,398,601	41,847,694
43	Interest Accrued (237)		118,648,155	119,224,245
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)		20,497,658	20,333,462
48	Miscellaneous Current and Accrued Liabilities (242)		76,469,862	69,280,619
49	Obligations Under Capital Leases-Current (243)		5,938,747	2,207,436
50	Derivative Instrument Liabilities (244)		28,451,943	69,761,281
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		25,100,250	32,083,864
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,109,292,384	957,256,162
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		32,324,218	33,717,019
57	Accumulated Deferred Investment Tax Credits (255)	266-267	18,259,559	22,505,122
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	176,253,764	301,476,278
60	Other Regulatory Liabilities (254)	278	115,848,090	77,876,318
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	306,993,377	285,986,998
63	Accum. Deferred Income Taxes-Other Property (282)		4,518,977,533	4,414,667,387
64	Accum. Deferred Income Taxes-Other (283)		603,137,231	657,526,736
65	Total Deferred Credits (lines 56 through 64)		5,771,793,772	5,793,755,858
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		22,012,602,336	22,086,633,996

Schedule Page: 112 Line No.: 28 Column: c

As of December 31, 2016, Account 228.2, Accumulated provision for injuries and damages, included expected insurance recoveries.

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

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

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	5,201,080,711	5,235,309,367		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,446,363,957	2,565,045,913		
5	Maintenance Expenses (402)	320-323	399,131,517	422,197,831		
6	Depreciation Expense (403)	336-337	709,094,974	697,031,280		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	38,577,000	37,690,560		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	5,083,195	4,989,371		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		150,507	437,693		
13	(Less) Regulatory Credits (407.4)			118,750		
14	Taxes Other Than Income Taxes (408.1)	262-263	189,632,535	185,302,308		
15	Income Taxes - Federal (409.1)	262-263	199,451,072	121,054,868		
16	- Other (409.1)	262-263	36,762,420	25,050,102		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	749,775,939	1,039,923,787		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	645,592,915	861,868,065		
19	Investment Tax Credit Adj. - Net (411.4)	266	-4,341,401	-4,756,408		
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)		188	320		
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)		4,124,088,612	4,231,980,170		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		1,076,992,099	1,003,329,197		

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
5,201,080,711	5,235,309,367					2
						3
2,446,363,957	2,565,045,913					4
399,131,517	422,197,831					5
709,094,974	697,031,280					6
						7
38,577,000	37,690,560					8
5,083,195	4,989,371					9
						10
						11
150,507	437,693					12
	118,750					13
189,632,535	185,302,308					14
199,451,072	121,054,868					15
36,762,420	25,050,102					16
749,775,939	1,039,923,787					17
645,592,915	861,868,065					18
-4,341,401	-4,756,408					19
						20
						21
188	320					22
						23
						24
4,124,088,612	4,231,980,170					25
1,076,992,099	1,003,329,197					26

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 2016/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)		1,076,992,099	1,003,329,197		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		1,554,611	1,722,065		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		1,617,614	1,740,032		
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)		72,626	124,007		
35	Nonoperating Rental Income (418)		198,175	187,080		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	17,851,891	13,544,949		
37	Interest and Dividend Income (419)		9,486,317	9,749,146		
38	Allowance for Other Funds Used During Construction (419.1)		27,450,081	32,841,065		
39	Miscellaneous Nonoperating Income (421)		1,157,759	478,158		
40	Gain on Disposition of Property (421.1)		1,777,232	1,427,360		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		57,785,826	58,085,784		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		29,654	555,201		
44	Miscellaneous Amortization (425)		1,344,292	1,343,975		
45	Donations (426.1)		2,317,647	2,364,473		
46	Life Insurance (426.2)		-6,068,477	-4,497,390		
47	Penalties (426.3)		25,500	1,526,588		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,710,497	2,593,244		
49	Other Deductions (426.5)		13,228,391	2,407,771		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		12,587,504	6,293,862		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	280,899	299,513		
53	Income Taxes-Federal (409.2)	262-263	-41,603,403	4,267,107		
54	Income Taxes-Other (409.2)	262-263	-5,653,211	579,829		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	148,815,498	128,771,334		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	103,275,215	131,834,874		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		311,468	553,152		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-1,746,900	1,529,757		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		46,945,222	50,262,165		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		359,474,830	356,471,778		
63	Amort. of Debt Disc. and Expense (428)		4,142,215	4,088,677		
64	Amortization of Loss on Reaquired Debt (428.1)		667,665	832,212		
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)		9,137	19,377		
68	Other Interest Expense (431)		12,460,408	14,445,893		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		15,316,302	17,591,087		
70	Net Interest Charges (Total of lines 62 thru 69)		361,426,927	358,255,824		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		762,510,394	695,335,538		
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)		762,510,394	695,335,538		

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, 2016 and 2015, depreciation expense associated with transportation equipment were $14,483,977 and $14,214,593, 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, 2016 and 2015, payroll taxes were $38,739,981 and $39,835,178, 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 2016/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		2,861,256,994	3,135,214,887
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)		744,658,503	681,790,589
17	Appropriations of Retained Earnings (Acct. 436)			
18	Appropriation of excess earnings at certain hydroelectric generating facilities	215.1	-8,918,577	(5,674,637)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-8,918,577	(5,674,637)
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	-875,000,000	(950,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-875,000,000	(950,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings	216.1	56,510,988	88,057
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,778,346,006	2,861,256,994
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		25,254,017	16,335,440
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		25,254,017	16,335,440
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		2,803,600,023	2,877,592,434
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		155,605,539	142,148,647
50	Equity in Earnings for Year (Credit) (Account 418.1)		17,851,891	13,544,949
51	(Less) Dividends Received (Debit)			
52	Transfers to/from Unappropriated Retained Earnings (Account 216)		-56,510,988	(88,057)
53	Balance-End of Year (Total lines 49 thru 52)		116,946,442	155,605,539

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

Outstanding shares of preferred stock as of December 31, 2016 and dividends on preferred stock during the year ended December 31, 2016, 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, 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.: 37 Column: c

Declared and paid dividends from subsidiaries of PacifiCorp during the year ended December 31, 2016, were as follows:

Pacific Minerals, Inc.	$55,000,000
Fossil Rock Fuels, LLC	1,430,267
Trapper Mining Inc.	80,721
	$56,510,988

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

In September 2015, Trapper Mining Inc., a subsidiary of PacifiCorp, paid a dividend of $88,057 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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/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)	762,510,394	695,335,538
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	725,220,132	712,627,877
5	Amortization:	45,030,703	44,050,122
6			
7			
8	Deferred Income Taxes (Net)	149,723,307	174,992,182
9	Investment Tax Credit Adjustment (Net)	-4,652,869	-5,309,560
10	Net (Increase) Decrease in Receivables	-26,219,152	-4,106,411
11	Net (Increase) Decrease in Inventory	-20,966,443	-7,282,585
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-166,766,587	20,473,475
14	Net (Increase) Decrease in Other Regulatory Assets	105,266,641	48,439,923
15	Net Increase (Decrease) in Other Regulatory Liabilities	16,847,524	14,305,404
16	(Less) Allowance for Other Funds Used During Construction	27,450,081	32,841,065
17	(Less) Undistributed Earnings from Subsidiary Companies	-38,659,097	13,456,892
18	Amounts Due To/From Affiliates (Net)	5,365,962	117,602,515
19	Derivative Collateral (Net)	6,300,000	-46,700,000
20	Other Operating Activities:	4,212,127	5,756,910
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,613,080,755	1,723,887,433
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-930,851,398	-948,488,007
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	-27,450,081	-32,841,065
31	Other (provide details in footnote):	-301,580	-22,770,214
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-903,702,897	-938,417,156
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	8,657,775	19,089,066
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-1,672,000	-216,000
40	Contributions and Advances from Assoc. and Subsidiary Companies	2,033,659	
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other Investing Activities:	-438,149	-484,494
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-895,121,612	-920,028,584
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		249,680,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)	249,910,111	
67	Other (provide details in footnote):		15,237,000
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	249,910,111	264,917,000
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-66,142,000	-122,199,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-15,921,244	-2,600,477
77	Repayment of Capital Lease Obligations	-1,641,181	-1,382,004
78	Net Decrease in Short-Term Debt (c)		-972
79			
80	Dividends on Preferred Stock	-161,902	-161,902
81	Dividends on Common Stock	-875,000,000	-950,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-708,956,216	-811,427,355
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	9,002,927	-7,568,506
87			
88	Cash and Cash Equivalents at Beginning of Period	5,907,820	13,476,326
89			
90	Cash and Cash Equivalents at End of period	14,910,747	5,907,820

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

Includes depreciation expense associated with transportation equipment and capital lease assets of $16,125,158 and $15,596,597 during the years ended December 31, 2016 and 2015, respectively.

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

	Years Ended December 31, 2016	Years Ended December 31, 2015
Amortization of software development & other intangibles	$39,921,292	$39,034,535
Amortization of electric plant acquisition adjustments	5,083,195	4,989,371
Amortization of a regulatory asset	26,216	26,216
	$45,030,703	$44,050,122

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

	Years Ended December 31, 2016	Years Ended December 31, 2015
Depreciation and depletion included in cost of fuel	$ 2,043,175	$ 1,876,649
Net (gain)/loss on sale of property	(1,822,720)	390,138
Write-off of assets under construction	7,170,982	3,748,844
Change in corporate owned life insurance cash surrender value	(6,044,333)	(4,474,180)
Amortization of debt issuance expenses and bond discount/premium	4,131,189	4,077,651
Other	(1,266,166)	137,808
	$ 4,212,127	$ 5,756,910

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

During the year ended December 31, 2016, the acquisition of certain transmission facilities and associated electric plant from Flowell Electric Association, Inc., subject to Commission approval, were as follows:

Account 101, Electric plant in service	$ (387,367)
Account 108, Accumulated provision for depreciation of electric utility plant	85,787
	$ (301,580)

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

During the year ended December 31, 2015, the acquisition of Eagle Mountain City distribution and transmission assets and liabilities were as follows:

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, 2016	Years Ended December 31, 2015
Other investments/special funds	$ 1,818,766	$ 1,377,796
Temporary facilities	45,628	56,895
Restricted cash	141,908	3,826,237
Investment in long-term incentive plan securities	(2,444,451)	(5,745,422)
	$ (438,149)	$ (484,494)

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

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

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

	Years Ended December 31, 2016	2015
Net repayments of affiliate borrowing from subsidiary company, Pacific Minerals, Inc.	$(15,237,000)	$ -
Long-term debt issuance and other deferred financing costs	(684,244)	(2,600,477)
	$(15,921,244)	$(2,600,477)

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

NOTES TO FINANCIAL STATEMENTS

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

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

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 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):

	2016	2015
Cash (131)	$ 15	$ 6
Temporary cash investments (136)	—	—
Total cash and cash equivalents	$ 15	$ 6

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, 2016 and 2015, 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):

	2016	2015
Beginning balance	$ 7	$ 7
Charged to operating costs and expenses, net	12	10
Write-offs, net	(12)	(10)
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 liabilities or 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.

Impairment

PacifiCorp evaluates long-lived assets for impairment, including utility plant, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the carrying value is written down to the estimated fair value and any resulting impairment loss is reflected on the Statement of Income. The impacts of regulation are considered when evaluating the carrying value of regulated assets.

Revenue Recognition

Revenue is recognized as electricity is delivered or services are provided. Revenue recognized includes billed and unbilled amounts. As of December 31, 2016 and 2015, unbilled revenue was $275 million and $245 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 $421 million and $437 million as of December 31, 2016 and 2015, respectively, and regulatory liabilities of $9 million and $12 million as of December 31, 2016 and 2015, 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 March 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2017-07, which amends FASB Accounting Standards Codification ("ASC") Subtopic 715, "Compensation – Retirement Benefits." The amendments in this guidance require that an employer disaggregate the service component from the other components of net benefit cost. Employers should report the service cost component in the same line item or items as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit cost are required to be presented in the income statement separately from the service cost component and outside a subtotal of income from operations, if one is presented. Additionally, the guidance will only allow the service cost component of net benefit cost to be eligible for capitalization when applicable. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted, and is required to be adopted retrospectively. PacifiCorp is currently evaluating the impact of adopting this guidance on its financial statements and disclosures included within Notes to Financial Statements.

In November 2016, the FASB issued ASU No. 2016-18, which amends FASB ASC Subtopic 230-10, "Statement of Cash Flows - Overall." The amendments in this guidance require that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted, and is required to be adopted retrospectively. PacifiCorp is currently evaluating the impact of adopting this guidance on its financial statements and disclosures included within Notes to Financial Statements.

In August 2016, the FASB issued ASU No. 2016-15, which amends FASB ASC Topic 230, "Statement of Cash Flows." The amendments in this guidance address the classification of eight specific cash flow issues within the statement of cash flows with the objective of reducing the existing diversity in practice. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted, and is required to be adopted retrospectively. PacifiCorp is currently evaluating the impact of adopting this guidance on its financial statements.

In February 2016, the FASB issued ASU No. 2016-02, which creates FASB ASC Topic 842, "Leases" and supersedes Topic 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 balance sheet 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. The impact of this update is immaterial to PacifiCorp's 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. During 2016, the FASB issued several ASUs that clarify the implementation guidance for ASU No. 2014-09 but do not change the core principle of the guidance. 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. PacifiCorp currently does not expect the timing and amount of revenue currently recognized to be materially different after adoption of the new guidance as a majority of revenue is recognized equal to what PacifiCorp has the right to invoice as it corresponds directly with the value to the customer of PacifiCorp’s performance to date. PacifiCorp’s current plan is to quantitatively disaggregate revenue in the required financial statement footnote by customer class and jurisdiction.

Subsequent Events

PacifiCorp has evaluated the impact of events occurring after December 31, 2016 up to February 24, 2017, 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 14, 2017. 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%, for the years ended December 31, 2016 and 2015.

(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, 2016 (dollars in millions):

	PacifiCorp Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Jim Bridger Nos. 1 - 4	67%	$ 1,420	$ 586	$ 10
Hunter No. 1	94	473	157	1
Hunter No. 2	60	296	96	—
Wyodak	80	467	197	1
Colstrip Nos. 3 and 4	10	244	132	5
Hermiston	50	178	76	2
Craig Nos. 1 and 2	19	325	226	32
Hayden No. 1	25	74	32	—
Hayden No. 2	13	43	20	—
Foote Creek	79	39	25	—
Transmission and distribution facilities	Various	777	275	61
Total		$ 4,336	$ 1,822	$ 112

(5) Regulatory Matters

Regulatory Assets

PacifiCorp had regulatory assets not earning a return on investment of $1.013 billion and $1.096 billion as of December 31, 2016 and 2015, respectively.

Utah Mine Disposition

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 2015, PacifiCorp received approval from the commissions.

In December 2014, PacifiCorp filed an advice letter with the California Public Utility Commission ("CPUC") to request approval to sell certain Utah mining assets and to establish memorandum accounts to track the costs associated with the Utah Mine Disposition for future recovery. 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. On February 6, 2017, a joint motion was filed with the CPUC seeking approval of a settlement agreement reached by PacifiCorp and all other parties. The agreement states, among other things, that the decision to sell certain Utah mining assets is in the public interest. Parties also reserve their rights to additional testimony, briefs, and hearings to the extent the CPUC determines that additional California Environmental Quality Act proceedings are necessary. A CPUC decision on the joint motion and settlement agreement is expected in 2017.

(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):

2016:		
Credit facilities	$	1,000
Less:		
Short-term debt		(270)
Tax-exempt bond support		(142)
Net credit facilities	$	588
2015:		
Credit facilities	$	1,200
Less:		
Short-term debt		(20)
Tax-exempt bond support and letters of credit		(160)
Net credit facilities	$	1,020

PacifiCorp has a $600 million unsecured credit facility expiring in March 2018 and a $400 million unsecured credit facility with a stated maturity of June 2019 and which has two one-year extension options subject to bank consent. 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, 2016 and 2015, the weighted average interest rate on commercial paper borrowings outstanding was 0.96% and 0.65%, 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, 2016, PacifiCorp was in compliance with the covenants of its credit facilities.

As of December 31, 2016 and 2015, PacifiCorp had $255 million and $310 million, respectively, of fully available letters of credit issued under committed arrangements, of which $10 million as of December 31, 2015 were issued under the credit facilities. These letters of credit support PacifiCorp's variable-rate tax-exempt bond obligations and expire through March 2019.

As of December 31, 2016, PacifiCorp had approximately $14 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, 2016 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.

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 $26 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2016.

PacifiCorp has entered into long-term agreements that qualify as capital leases and expire at various dates through March 2035 for transportation services, a power purchase agreement 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 $27 million and $32 million as of December 31, 2016 and 2015, respectively, were included in net utility plant in the Comparative Balance Sheet.

As of December 31, 2016, the annual principal maturities of long-term debt and total capital lease obligations for 2017 and thereafter are as follows (in millions):

	Long-term Debt	Capital Lease Obligations	Total
2017	$ 52	$ 9	$ 61
2018	586	4	590
2019	350	4	354
2020	38	3	41
2021	420	6	426
Thereafter	5,647	20	5,667
Total	7,093	46	7,139
Unamortized discount	(11)	—	(11)
Amounts representing interest	—	(19)	(19)
Total	$ 7,082	$ 27	$ 7,109

(8) Income Taxes

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

	2016	2015
Current:		
Federal	$ 158	$ 125
State	31	26
Total	189	151
Deferred:		
Federal	129	146
State	21	29
Total	150	175
Investment tax credits	(5)	(5)
Total income tax expense	$ 334	$ 321

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:

	2016	2015
Federal statutory income tax rate	35%	35%
State income taxes, net of federal income tax benefit	3	3
Federal income tax credits	(6)	(6)
Other	(2)	—
Effective income tax rate	30%	32%

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):

	2016	2015
Deferred income tax assets:		
Employee benefits	$ 202	$ 190
Derivative contracts and unamortized contract values	67	94
State carryforwards	69	69
Loss contingencies	—	56
Asset retirement obligations	78	81
Regulatory liabilities	44	30
Other	82	86
	542	606
Deferred income tax liabilities:		
Property, plant and equipment	(4,826)	(4,701)
Regulatory assets	(586)	(639)
Other	(17)	(18)
	(5,429)	(5,358)
Net deferred income tax liability	$ (4,887)	$ (4,752)

The following table provides PacifiCorp's net operating loss and tax credit carryforwards and expiration dates as of December 31, 2016 (in millions):

	State
Net operating loss carryforwards	$ 1,415
Deferred income taxes on net operating loss carryforwards	$ 52
Expiration dates	2017 - 2032
Tax credit carryforwards	$ 17
Expiration dates	2017 - indefinite

The United States Internal Revenue Service has closed its examination of PacifiCorp's income tax returns through December 31, 2009. The statute of limitations for PacifiCorp's state income tax returns have expired through December 31, 2009, with the exception of California, Oregon and Utah, for which the statute of limitations have expired through March 31, 2006.

(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 non-contributory defined benefit pension plans, collectively 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. 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 earned benefits based on a cash balance formula through December 31, 2016. Effective January 1, 2017, non-union employee participants with a cash balance benefit in the Retirement Plan are no longer eligible to receive pay credits in their 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. The SERP was closed to new participants as of March 21, 2006 and froze future accruals for active participants as of December 31, 2014.

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" 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	
	2016	2015	2016	2015
Service cost	$ 4	$ 4	$ 2	$ 3
Interest cost	54	53	15	16
Expected return on plan assets	(75)	(77)	(21)	(23)
Net amortization	34	42	(5)	(4)
Net period benefit cost (credit)	$ 17	$ 22	$ (9)	$ (8)

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	
	2016	2015	2016	2015
Plan assets at fair value, beginning of year	$ 1,043	$ 1,146	$ 305	$ 482
Employer contributions	5	4	1	1
Participant contributions	—	—	6	6
Actual return on plan assets	51	—	17	1
Settlement	—	—	—	(150)
Benefits paid	(100)	(107)	(27)	(35)
Plan assets at fair value, end of year	$ 999	$ 1,043	$ 302	$ 305

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

	Pension		Other Postretirement	
	2016	2015	2016	2015
Benefit obligation, beginning of year	$ 1,289	$ 1,378	$ 362	$ 539
Service cost	4	4	2	3
Interest cost	54	53	15	16
Participant contributions	—	—	6	6
Actuarial (gain) loss	29	(39)	—	(17)
Settlement	—	—	—	(150)
Benefits paid	(100)	(107)	(27)	(35)
Benefit obligation, end of year	$ 1,276	$ 1,289	$ 358	$ 362
Accumulated benefit obligation, end of year	$ 1,276	$ 1,289		

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	
	2016	2015	2016	2015
Plan assets at fair value, end of year	$ 999	$ 1,043	$ 302	$ 305
Less - Benefit obligation, end of year	1,276	1,289	358	362
Funded status	$ (277)	$ (246)	$ (56)	$ (57)
Amounts recognized on the Comparative Balance Sheet:				
Miscellaneous current and accrued liabilities	$ (5)	$ (4)	$ —	$ —
Accumulated provision for pension and benefits	(272)	(242)	(56)	(57)
Amounts recognized	$ (277)	$ (246)	$ (56)	$ (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 $55 million and $52 million as of December 31, 2016 and 2015, 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	
	2016	2015	2016	2015
Net loss	$ 518	$ 508	$ 39	$ 36
Prior service credit	—	(13)	(13)	(19)
Regulatory deferrals	(7)	(3)	8	9
Total	$ 511	$ 492	$ 34	$ 26

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2016 and 2015 is as follows (in millions):

	Regulatory Asset	Accumulated Other Comprehensive Loss	Total
Pension			
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
Net loss arising during the year	51	2	53
Net amortization	(33)	(1)	(34)
Total	18	1	19
Balance, December 31, 2016	$ 491	$ 20	$ 511

	Regulatory Asset
Other Postretirement	
Balance, December 31, 2014	$ 17
Net loss arising during the year	5
Net amortization	4
Total	9
Balance, December 31, 2015	26
Net loss arising during the year	3
Net amortization	5
Total	8
Balance, December 31, 2016	$ 34

The net loss, prior service credit and regulatory deferrals that will be amortized in 2017 into net periodic benefit cost are estimated to be as follows (in millions):

	Net Loss	Prior Service Credit	Regulatory Deferrals	Total
Pension	$ 16	$ —	$ (2)	$ 14
Other postretirement	—	(7)	1	(6)
Total	$ 16	$ (7)	$ (1)	$ 8

Plan Assumptions

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

	Pension		Other Postretirement	
	2016	2015	2016	2015
Benefit obligations as of December 31:				
Discount rate	4.05%	4.40%	4.05%	4.35%
Rate of compensation increase	N/A	2.75	N/A	N/A
Net periodic benefit cost for the years ended December 31:				
Discount rate	4.40%	4.00%	4.35%	3.99%
Expected return on plan assets	7.50	7.50	7.50	7.08
Rate of compensation increase	2.75	2.75	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 a plan amendment effective on January 1, 2017, the benefit obligation for the Retirement Plan is no longer affected by future increases in compensation. 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.

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $5 million and $- million, respectively, during 2017. 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 2017 through 2021 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	**Other Postretirement**
2017	$ 105	$ 28
2018	109	28
2019	108	27
2020	104	30
2021	97	26
2022-2026	426	116

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, 2016:

	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

PacifiCorp adopted ASU No. 2015-07, "Fair Value Measurement (Topic 820) - Disclosures for Investments in Certain Entities that Calculate Net Asset Value per Share (or its Equivalent)" effective January 1, 2016 under a retrospective method.

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, 2016:				
Cash equivalents	$ —	$ 10	$ —	$ 10
Debt securities:				
United States government obligations	25	—	—	25
Corporate obligations	—	36	—	36
Municipal obligations	—	6	—	6
Agency, asset and mortgage-backed obligations	—	37	—	37
Equity securities:				
United States companies	389	—	—	389
International companies	15	—	—	15
Investment funds(2)	83	—	—	83
Total assets in the fair value hierarchy	$ 512	$ 89	$ —	601
Investment funds(2) measured at net asset value				337
Limited partnership interests(3) measured at net asset value				61
Investments at fair value				$ 999
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	—	—	83
Total assets in the fair value hierarchy	$ 527	$ 100	$ —	627
Investment funds(2) measured at net asset value				351
Limited partnership interests(3) measured at net asset value				65
Investments at fair value				$ 1,043

(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 54% and 46% respectively, for 2016 and 53% and 47%, respectively, for 2015, and are invested in United States and international securities of approximately 39% and 61%, respectively, for 2016 and 40% and 60%, respectively, for 2015.

(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, 2016:				
Cash and cash equivalents	$ 4	$ 1	$ —	$ 5
Debt securities:				
United States government obligations	11	—	—	11
Corporate obligations	—	13	—	13
Municipal obligations	—	2	—	2
Agency, asset and mortgage-backed obligations	—	13	—	13
Equity securities:				
United States companies	93	—	—	93
International companies	4	—	—	4
Investment funds(2)	32	—	—	32
Total assets in the fair value hierarchy	$ 144	$ 29	$ —	173
Investment funds(2) measured at net asset value				125
Limited partnership interests(3) measured at net asset value				4
Investments at fair value				$ 302
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	—	—	32
Total assets in the fair value hierarchy	$ 144	$ 31	$ —	175
Investment funds(2) measured at net asset value				126
Limited partnership interests(3) measured at net asset value				4
Investments at fair value				$ 305

(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 62% and 38%, respectively, for 2016 and 61% and 39%, respectively, for 2015, and are invested in United States and international securities of approximately 71% and 29%, respectively, for 2016 and 67% and 33%, respectively, for 2015.

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

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 based on observable market inputs. Shares of mutual funds not registered under the Securities Act of 1933, private equity limited partnership interests, common and commingled trust funds and investment entities are reported at fair value based on the net asset value per unit, which is used for expedience purposes. A fund's net asset value is based on the fair value of the underlying assets held by the fund less its liabilities.

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. PacifiCorp recorded its estimate of the withdrawal obligation in December 2014 when withdrawal was considered probable and deferred the portion of the obligation considered probable of recovery to a regulatory asset. PacifiCorp has subsequently revised its estimate due to changes in facts and circumstances for a withdrawal occurring by July 2015. As communicated in a letter received in August 2016, the plan trustees have determined a withdrawal liability of $115 million. Energy West Mining Company began making installment payments in November 2016 and has the option to elect a lump sum payment to settle the withdrawal obligation. The ultimate amount paid by Energy West Mining Company to settle the obligation is dependent on a variety of factors, including the results of ongoing negotiations with the plan trustees.

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, 2016	2015	Funding improvement plan	Surcharge imposed under PPA(1)	Contributions(1) 2016	2015	Year contributions to plan exceeded more than 5% of total contributions(2)
UMWA 1974 Pension Plan	52-1050282	Critical and Declining	Critical and Declining	Implemented	Yes	$ —	$ 1	None
Local 57 Trust Fund	87-0640888	At least 80%	At least 80%	None	None	$ 8	$ 8	2015, 2014

(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 years beginning July 1, 2014 and 2013. Information for the plan year beginning July 1, 2015 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 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, as of January 1, 2017, all 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 $34 million and $35 million and for the years ended December 31, 2016 and 2015, 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 $917 million and $894 million as of December 31, 2016 and 2015, respectively.

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

	2016	2015
Beginning balance	$ 224	$ 135
Change in estimated costs	2	62
Additions	—	30
Retirements	(19)	(10)
Accretion	8	7
Ending balance	$ 215	$ 224

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, manage, mitigate, monitor and report, 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, 2016:					
Not designated as hedging contracts[1]:					
Commodity assets	$ 24	$ 2	$ 1	$ —	$ 27
Commodity liabilities	(6)	—	(14)	(84)	(104)
Total	18	2	(13)	(84)	(77)
Total derivatives	18	2	(13)	(84)	(77)
Cash collateral receivable	—	—	10	59	69
Total derivatives - net basis	$ 18	$ 2	$ (3)	$ (25)	$ (8)
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)

(1) PacifiCorp's commodity derivatives are generally included in rates and as of December 31, 2016 and 2015, a regulatory asset of $73 million and $133 million, respectively, was recorded related to the net derivative liability of $77 million and $136 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):

	2016	2015
Beginning balance	$ 133	$ 85
Changes in fair value recognized in regulatory assets	(27)	82
Net gains reclassified to operating revenue	10	40
Net losses reclassified to energy costs	(43)	(74)
Ending balance	$ 73	$ 133

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	2016	2015
Electricity (sales) purchases	Megawatt hours	(3)	1
Natural gas purchases	Decatherms	84	111
Fuel oil purchases	Gallons	11	11

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, 2016, 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 $97 million and $142 million as of December 31, 2016 and 2015, respectively, for which PacifiCorp had posted collateral of $69 million and $75 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, 2016 and 2015, PacifiCorp would have been required to post $22 million and $64 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, 2016 and December 31, 2015, PacifiCorp would have been required to post $221 million and $261 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, 2016:					
Assets:					
Commodity derivatives	$ —	$ 27	$ —	$ (7)	$ 20
Money market mutual funds(2)	13	—	—	—	13
Investment funds	17	—	—	—	17
	$ 30	$ 27	$ —	$ (7)	$ 50
Liabilities - Commodity derivatives	$ —	$ (104)	$ —	$ 76	$ (28)
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)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $69 million and $75 million as of December 31, 2016 and 2015, respectively.

(2) Amounts are included in other special funds, special deposits and temporary cash investments on the Comparative Balance Sheet. The fair value of these money market mutual funds 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 and are primarily accounted for as available-for-sale securities. When available, 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. In the absence of a quoted market price or net asset value of an identical security, the fair value is determined using pricing models or net asset values based on observable market inputs and quoted market prices of securities with similar characteristics.

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):

	2016		2015	
	Carrying Value	**Fair Value**	**Carrying Value**	**Fair Value**
Long-term debt	$ 7,082	$ 8,204	$ 7,147	$ 8,210

(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.

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 begin no earlier than 2020.

Congress failed to pass legislation needed to implement the original KHSA. Hence, 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. On April 6, 2016, PacifiCorp, the states of California and Oregon, and the United States Departments of the Interior and Commerce and other stakeholders executed an amendment to the KHSA. Consistent with the terms of the amended KHSA, on September 23, 2016, PacifiCorp and the Klamath River Renewal Corporation ("KRRC") jointly filed an application with the FERC to transfer the license for the four mainstem Klamath River hydroelectric generating facilities from PacifiCorp to the KRRC. Also on September 23, 2016, the KRRC filed an application with the FERC to surrender the license and decommission the facilities. The KRRC's license surrender application included a request for the FERC to refrain from acting on the surrender application until after the transfer of the license to the KRRC is effective.

Under the amended KHSA, PacifiCorp and its customers continue to be protected from uncapped dam removal costs and liabilities. The KRRC must indemnify PacifiCorp from liabilities associated with dam removal. 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. California voters approved a water bond measure in November 2014 from which the state of California's contribution towards facilities removal costs will be drawn. In accordance with this bond measure, additional funding of up to $250 million for facilities removal costs was included in the California state budget in 2016, with the funding effective for at least five years. 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 removal to proceed.

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

As of December 31, 2016, PacifiCorp's assets included $68 million of costs associated with the Klamath hydroelectric system's mainstem dams and the associated relicensing and settlement costs, which are being depreciated and amortized in accordance with state regulatory approvals through either December 31, 2019, or December 31, 2022, depending upon the state jurisdiction.

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 $227 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, 2016 are as follows (in millions):

	2017	2018	2019	2020	2021	2022 and Thereafter	Total
Contract type:							
Purchased electricity contracts - commercially operable	$ 253	$ 160	$ 157	$ 157	$ 145	$ 1,630	$ 2,502
Purchased electricity contracts - non-commercially operable	10	13	17	17	18	390	465
Fuel contracts	796	616	596	507	346	1,407	4,268
Construction commitments	62	46	26	4	1	4	143
Transmission	109	106	90	61	47	467	880
Operating leases and easements	5	5	5	5	4	39	63
Maintenance, service and other contracts	53	29	31	17	20	68	218
Total commitments	$ 1,288	$ 975	$ 922	$ 768	$ 581	$ 4,005	$ 8,539

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 $14 million for 2016 and $13 million for 2015.

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 operating 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 2016 and 2015 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 years ended December 31, 2016 and 2015.

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 2017, 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 2017.

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, 2016, 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, 2016, PacifiCorp's actual common equity percentage, as calculated under this measure, was 51%, and PacifiCorp would have been permitted to dividend $1.9 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, 2016, 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):

	2016	2015
Interest paid, net of amounts capitalized	$ 351	$ 342
Income taxes paid, net[1]	$ 187	$ 32
Supplemental disclosure of non-cash investing and financing activities:		
Accounts payable related to utility plant additions	$ 101	$ 147
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.

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 2016/Q4

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

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
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				(13,665,680)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				549,221
3	Preceding Quarter/Year to Date Changes in Fair Value				1,101,821
4	Total (lines 2 and 3)				1,651,042
5	Balance of Account 219 at End of Preceding Quarter/Year				(12,014,638)
6	Balance of Account 219 at Beginning of Current Year				(12,014,638)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				488,311
8	Current Quarter/Year to Date Changes in Fair Value				(1,067,871)
9	Total (lines 7 and 8)				(579,560)
10	Balance of Account 219 at End of Current Quarter/Year				(12,594,198)

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Insert Footnote at Line 1 to 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			(13,665,680)		
2			549,221		
3			1,101,821		
4			1,651,042	695,335,538	696,986,580
5			(12,014,638)		
6			(12,014,638)		
7			488,311		
8			(1,067,871)		
9			(579,560)	762,510,394	761,930,834
10			(12,594,198)		

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 2016/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)	26,872,537,513	26,872,537,513
4	Property Under Capital Leases	27,028,781	27,028,781
5	Plant Purchased or Sold		
6	Completed Construction not Classified	191,897,135	191,897,135
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	27,091,463,429	27,091,463,429
9	Leased to Others		
10	Held for Future Use	23,502,790	23,502,790
11	Construction Work in Progress	655,882,614	655,882,614
12	Acquisition Adjustments	156,468,483	156,468,483
13	Total Utility Plant (8 thru 12)	27,927,317,316	27,927,317,316
14	Accum Prov for Depr, Amort, & Depl	9,693,954,266	9,693,954,266
15	Net Utility Plant (13 less 14)	18,233,363,050	18,233,363,050
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	9,026,397,312	9,026,397,312
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	550,553,312	550,553,312
22	Total In Service (18 thru 21)	9,576,950,624	9,576,950,624
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	117,003,642	117,003,642
33	Total Accum Prov (equals 14) (22,26,30,31,32)	9,693,954,266	9,693,954,266

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
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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 2016/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	206,974,785	-177,719
4	(303) Miscellaneous Intangible Plant	669,757,688	51,991,761
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	876,732,473	51,814,042
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	93,556,326	20,122
9	(311) Structures and Improvements	1,011,697,865	9,211,821
10	(312) Boiler Plant Equipment	4,374,914,312	228,239,273
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	954,177,895	44,155,643
13	(315) Accessory Electric Equipment	484,708,784	6,003,686
14	(316) Misc. Power Plant Equipment	31,275,408	201,674
15	(317) Asset Retirement Costs for Steam Production	141,661,372	10,143,462
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	7,091,991,962	297,975,681
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	31,312,931	627,132
28	(331) Structures and Improvements	262,514,284	4,561,004
29	(332) Reservoirs, Dams, and Waterways	488,402,461	8,397,740
30	(333) Water Wheels, Turbines, and Generators	128,919,258	487,968
31	(334) Accessory Electric Equipment	79,819,536	1,824,262
32	(335) Misc. Power PLant Equipment	2,380,783	-2,932
33	(336) Roads, Railroads, and Bridges	22,170,609	1,276,758
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	1,015,519,862	17,171,932
36	D. Other Production Plant		
37	(340) Land and Land Rights	44,773,920	
38	(341) Structures and Improvements	227,589,347	118,051
39	(342) Fuel Holders, Products, and Accessories	15,904,296	740,155
40	(343) Prime Movers	2,930,023,773	50,747,743
41	(344) Generators	473,476,623	2,229,021
42	(345) Accessory Electric Equipment	326,256,540	1,249,496
43	(346) Misc. Power Plant Equipment	15,921,587	19,129
44	(347) Asset Retirement Costs for Other Production	13,031,355	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	4,046,977,441	55,103,595
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	12,154,489,265	370,251,208

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 2016/Q4

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
			206,797,066		3
44,319,775		-38,073	677,391,601		4
44,319,775		-38,073	884,188,667		5
					6
					7
1,641		-862,212	92,712,595		8
2,286,429		351	1,018,623,608		9
58,017,002		-34,299	4,545,102,284		10
					11
23,845,983			974,487,555		12
1,373,635		33,029	489,371,864		13
356,621		919	31,121,380		14
9,037,852	-887,420		141,879,562		15
94,919,163	-887,420	-862,212	7,293,298,848		16
					17
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					22
					23
					24
					25
					26
18		-97,950	31,842,095		27
140,271		-63,720	266,871,297		28
751,464		63,720	496,112,457		29
119,399			129,287,827		30
328,283			81,315,515		31
979			2,376,872		32
195,953			23,251,414		33
					34
1,536,367		-97,950	1,031,057,477		35
					36
		704,285	45,478,205		37
27,632		-8,452	227,671,314		38
410,936		3,743	16,237,258		39
57,604,049		-913,155	2,922,254,312		40
858,592		315,209	475,162,261		41
448,334		631,918	327,689,620		42
		-29,263	15,911,453		43
			13,031,355		44
59,349,543		704,285	4,043,435,778		45
155,805,073	-887,420	-255,877	12,367,792,103		46

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 2016/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	251,625,967	4,326,112
49	(352) Structures and Improvements	239,305,233	4,546,370
50	(353) Station Equipment	2,012,791,077	97,808,172
51	(354) Towers and Fixtures	1,288,991,817	2,140,800
52	(355) Poles and Fixtures	901,299,535	22,421,086
53	(356) Overhead Conductors and Devices	1,193,250,695	22,042,679
54	(357) Underground Conduit	3,519,566	-172
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)	5,910,756,444	153,285,047
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	62,461,151	796,264
61	(361) Structures and Improvements	110,250,312	2,354,138
62	(362) Station Equipment	971,676,422	31,672,784
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	1,120,755,209	39,320,107
65	(365) Overhead Conductors and Devices	724,069,029	19,504,360
66	(366) Underground Conduit	349,690,089	11,033,231
67	(367) Underground Conductors and Devices	820,180,898	23,991,529
68	(368) Line Transformers	1,274,134,081	45,536,275
69	(369) Services	709,528,257	34,747,237
70	(370) Meters	186,936,755	9,245,534
71	(371) Installations on Customer Premises	8,863,050	61,971
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	61,222,785	1,444,196
74	(374) Asset Retirement Costs for Distribution Plant	1,507,080	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	6,401,275,118	219,707,626
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	21,481,450	176,044
87	(390) Structures and Improvements	240,205,455	5,170,795
88	(391) Office Furniture and Equipment	80,556,278	5,622,539
89	(392) Transportation Equipment	110,652,440	3,994,617
90	(393) Stores Equipment	15,178,816	377,227
91	(394) Tools, Shop and Garage Equipment	64,061,851	2,250,713
92	(395) Laboratory Equipment	33,961,776	860,916
93	(396) Power Operated Equipment	168,265,144	5,416,614
94	(397) Communication Equipment	428,243,947	21,420,893
95	(398) Miscellaneous Equipment	8,135,600	259,442
96	SUBTOTAL (Enter Total of lines 86 thru 95)	1,170,742,757	45,549,800
97	(399) Other Tangible Property	2,559,113	
98	(399.1) Asset Retirement Costs for General Plant	39,748	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	1,173,341,618	45,549,800
100	TOTAL (Accounts 101 and 106)	26,516,594,918	840,607,723
101	(102) Electric Plant Purchased (See Instr. 8)	1,460,458	301,580
102	(Less) (102) Electric Plant Sold (See Instr. 8)	-561,324	-5,796,654
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	26,518,616,700	846,705,957

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
164,209		10,767	255,798,637		48
277,767		-935,766	242,638,070		49
8,957,450		2,700,514	2,104,342,313		50
-90,105		-82,247	1,291,140,475		51
2,570,981		-181,291	920,968,349		52
1,855,866		-97,393	1,213,340,115		53
			3,519,394		54
			8,035,354		55
			11,937,200		56
					57
13,736,168		1,414,584	6,051,719,907		58
					59
659		-1,142,824	62,113,932		60
218,754		-8,668	112,377,028		61
5,013,041		-999,004	997,337,161		62
					63
8,589,816		17,995	1,151,503,495		64
3,935,016			739,638,373		65
1,456,049			359,267,271		66
3,040,205			841,132,222		67
8,919,328		-1,181	1,310,749,847		68
785,022			743,490,472		69
3,217,995			192,964,294		70
87,864			8,837,157		71
					72
776,233			61,890,748		73
			1,507,080		74
36,039,982		-2,133,682	6,582,809,080		75
					76
					77
					78
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					82
					83
					84
					85
113,136			21,544,358		86
3,411,264		-3,380	241,961,606		87
11,085,898		40,999	75,133,918		88
4,293,716		261,250	110,614,591		89
196,863		39,600	15,398,780		90
1,942,367		-283,518	64,086,679		91
1,964,891		15,240	32,873,041		92
10,483,108			163,198,650		93
6,716,046		55,754	443,004,548		94
202,239		21,341	8,214,144		95
40,409,528		147,286	1,176,030,315		96
		-704,285	1,854,828		97
			39,748		98
40,409,528		-556,999	1,177,924,891		99
290,310,526	-887,420	-1,570,047	27,064,434,648		100
	-1,374,671	-387,367			101
	6,357,978				102
					103
290,310,526	-8,620,069	-1,957,414	27,064,434,648		104

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

Account 39921, Land owned in fee

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

Refer to footnote on line 97, column (b).

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

Refer to footnote on line 97, column (b).

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

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

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

Refer to footnote on Line 101, column (b).

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

Refer to footnote on line 101, column (b).

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

Refer to footnote on line 101, column (b).

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

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

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

Refer to footnote on line 102, column (b).

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

Refer to footnote on line 102, column (b).

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 2016/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	Barnes Butte Substation	2007	2025	746,268
3	Wild Horse Wind Plant	2007	2039	6,763,094
4	Twelve Mile Wind Plant	2007	2039	2,160,207
5	Jumbers Point Substation	2008	2022	1,173,276
6	Mountain Green Substation	2009	2025	284,996
7	Hoggard Substation	2009	2025	254,397
8	Oquirrh-Terminal 345kV Transmission Line	2009	2021	396,020
9	Bend Service Center	2010	2022	3,507,838
10	Legacy Substation	2010	2025	562,276
11	Aeolus Substation	2011	2020	1,013,577
12	Anticline Substation	2011	2020	964,043
13	Populus Substation	2011	2024	254,753
14	Snyderville Substation	2011	2017	253,401
15	Lassen Substation	2012	2018	683,318
16	Old Mill Substation	2012	2026	1,838,281
17	Chimney Butte-Paradise 230kV Transmission Line	2013	2025	598,457
18	Fiddlers Canyon Substation	2016	2028	1,136,587
19	Miscellaneous, each under $250,000:			912,001
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
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43				
44				
45				
46				
47	Total			23,502,790

Schedule Page: 214 Line No.: 3 Column: c

Land purchased for wind farms with an estimated construction date of 2039, subject to environmental and economic reviews and the timing of completion of the Energy Gateway Transmission Expansion Program.

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

Land purchased for wind farms with an estimated construction date of 2039, subject to environmental and economic reviews and the timing of completion of the Energy Gateway Transmission Expansion Program.

Schedule Page: 214 Line No.: 18 Column: a

In June 2016, Fiddlers Canyon Substation was transferred from Account 101, Electric plant in service, to Account 105, Electric plant held for future use.

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

Various dates and plans.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $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	MV-Star Software Replacement	3,622,173
3	Wallowa Falls Hydro Relicensing	2,686,462
4	Endur System Upgrade	2,143,265
5	Prospect No. 3 Hydro Relicensing	1,291,992
6		
7	Production:	
8	Wind Repowering/New Development/Safe Harbor Equipment Purchases	111,124,301
9	Craig U2 Selective Catalytic Reduction System	27,339,043
10	Lewis River System Relicensing Implementation	7,254,464
11	Jim Bridger U2 Replace Finishing Superheater	2,973,110
12	Oneida 3 Rotor Replacement	2,891,223
13	Prospect No. 1 Rehabilitation	1,874,018
14	Toketee Dam Rehabilitation Evaluation	1,620,902
15	Lewis River System Maximum Flood Improvement Study	1,522,562
16	Jim Bridger Replace 01/02 Emergency Diesel Generators	1,432,463
17	Oneida Water Conveyance Protection	1,414,736
18	Naughton U1 Feedwater High-Pressure Heater Replacement	1,038,868
19		
20	Transmission:	
21	Aeolus - Clover 500kV Line	80,741,062
22	Windstar - Populus 230 - 500kV Line	73,477,761
23	Boardman - Hemingway 500kV Line	55,878,860
24	Populus - Hemingway 500kV Line	50,542,670
25	Snow Goose 500 - 230kV Substation	29,165,659
26	Union Gap Substation Add 230 - 115kV Capacity	14,646,417
27	Oquirrh - Terminal 345kV Line	12,241,519
28	West Point - New 138kV Line and 40 MVa Substation	11,447,197
29	Vantage - Pomona Heights 230kV Line	11,039,688
30	Troutdale Substation 230kV Switchyard 115kV Ring Bus	9,237,959
31	Southwest WY - Silver Creek Build 138kV Line	6,564,216
32	Purgatory Flat New 138kV Substation	5,748,746
33	Wallula - McNary 230kV Line	5,102,851
34	Sigurd - Red Butte - Crystal 345kV Line	3,042,749
35	Sams Valley New 500 - 230kV Substation	1,719,639
36	Syracuse Substation - Install 2nd 345-138 kV Transformer TPL	1,504,794
37	Goshen - Jefferson - Montana Stateline 161kV Reconductor	1,375,150
38	Hazelwood and Fry Substations: Relay Replacement	1,147,486
39	Borah Substation: Replace Series Cap C341	1,105,505
40	California Lines 38 & 44 LiDAR	1,000,336
41		
42		
43	TOTAL	655,882,614

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 2016/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Distribution:	
2	Oregon Advanced Metering Infrastructure	4,022,847
3	Vineyard Substation and Timp-Vineyard 138kV Line Upgrades	3,830,616
4	Lassen Substation - New Substation	1,766,602
5	Stadelman Fruit, Yakima WA	1,135,988
6		
7	Miscellaneous Projects each under $1,000,000	98,166,715
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
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41		
42		
43	TOTAL	655,882,614

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 2016/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	8,565,801,806	8,565,801,806		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	709,094,974	709,094,974		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	30,594,113	30,594,113		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	739,689,087	739,689,087		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	245,497,947	245,497,947		
13	Cost of Removal	73,978,760	73,978,760		
14	Salvage (Credit)	3,898,603	3,898,603		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	315,578,104	315,578,104		
16	Other Debit or Cr. Items (Describe, details in footnote):	36,484,523	36,484,523		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	9,026,397,312	9,026,397,312		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	3,044,271,915	3,044,271,915		
21	Nuclear Production				
22	Hydraulic Production-Conventional	359,720,139	359,720,139		
23	Hydraulic Production-Pumped Storage				
24	Other Production	916,111,993	916,111,993		
25	Transmission	1,592,275,183	1,592,275,183		
26	Distribution	2,679,701,608	2,679,701,608		
27	Regional Transmission and Market Operation				
28	General	434,316,474	434,316,474		
29	TOTAL (Enter Total of lines 20 thru 28)	9,026,397,312	9,026,397,312		

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

Account 143, Other accounts receivable: depreciation expense billed to joint owners	$ 265,926
Account 182.3, Other regulatory assets or Account 254, Other regulatory liabilities: asset retirement obligation asset depreciation	17,761,421
Account 182.3, Other regulatory assets: deferral of Carbon depreciation	(5,081,468)
Account 182.3, Other regulatory assets: deferral of increased depreciation, due to depreciation study rates, net of amortization	1,174,622
Transportation depreciation charged to operations and maintenance expense and construction work in progress based on usage activity	14,483,977
Account 503, Steam from other sources: Blundell depletion	23,172
Account 503, Steam from other sources: Blundell depreciation	1,966,463
Total Other Accounts	$ 30,594,113

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	$ 18,137,493
Other items include: - 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	18,347,030
Total Other Debit or Cr. Items	$ 36,484,523

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 2016/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			148,768,673
5	SUBTOTAL			196,728,674
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			7,010,024
22	SUBTOTAL			13,048,024
23				
24	FOSSIL ROCK FUELS, LLC	2011		
25	Paid-in Capital			31,538,428
26	Undistributed Subsidiary Earnings			-173,158
27	SUBTOTAL			31,365,270
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 83,504,772		TOTAL	241,143,969

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 2016/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		1		2
		47,960,000		3
15,330,815		109,099,488		4
15,330,815		157,059,489		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
402,201		7,331,504		21
402,201		13,369,504		22
				23
				24
		29,504,770		25
2,118,875		515,450		26
2,118,875		30,020,220		27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
17,851,891		200,451,214		42

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

Pacific Minerals, Inc. is a wholly owned subsidiary of PacifiCorp that holds a 66.67% 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.: 4 Column: g

For the year ended December 31, 2016, Pacific Minerals, Inc., a wholly owned subsidiary of PacifiCorp, declared and paid dividends of $55.0 million to PacifiCorp.

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

In September 2016, Trapper Mining Inc., a subsidiary of PacifiCorp, paid a dividend of $80,721 to PacifiCorp.

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

For the year ended December 31, 2016, Fossil Rock Fuels, LLC, a wholly owned subsidiary of PacifiCorp, returned $2.0 million of capital to PacifiCorp.

Schedule Page: 224 Line No.: 26 Column: g

For the year ended December 31, 2016, Fossil Rock Fuels, LLC, a wholly owned subsidiary of PacifiCorp, declared and paid dividends of $1.4 million to PacifiCorp.

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)	192,305,988	214,693,832	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)	134,703,542	142,252,190	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	84,947,332	73,437,874	Electric
8	Transmission Plant (Estimated)	653,625	715,287	Electric
9	Distribution Plant (Estimated)	12,772,256	11,798,517	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	55,338	57,418	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	233,132,093	228,261,286	
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)	425,438,081	442,955,118	

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

During the year ended December 31, 2016, inventory associated with the Carbon coal-fueled generation plant retired in December 2015, was transferred to Account 182.3, Other regulatory assets.

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

General plant materials and supplies

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

General plant materials and supplies

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 2016/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)	2017 No. (d)	2017 Amt. (e)
1	Balance-Beginning of Year	558,841.00		151,733.00	
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	27,605.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	531,236.00		151,733.00	
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 2016/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.

2018		2019		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
156,646.00		151,417.00		4,072,762.00		5,091,399.00		1
								2
								3
								4
				156,644.00		156,644.00		5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						27,605.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
156,646.00		151,417.00		4,229,406.00		5,220,438.00		29
								30
								31
								32
								33
								34
								35
2,259.00		2,259.00		110,921.00		119,957.00		36
				4,528.00		4,528.00		37
								38
				2,269.00		4,528.00		39
2,259.00		2,259.00		113,180.00		119,957.00		40
								41
								42
								43
								44
								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	Q0542	2,678	561.6		
3	Q1918	10,242	561.6	10,242	456
4	Q1919	13,811	561.6	13,811	456
5	Q1918-1919	2,876	561.6	2,876	456
6	Q1977	26,349	561.6	26,349	456
7	Q2065	2,776	561.6	2,776	456
8	Q2068	4,581	561.6		
9	Q2068-2072	3,424	561.6	3,424	456
10	Q2089	2,781	561.6		
11	Q2111	959	561.6		
12	Q2111-2115	8,432	561.6	8,432	456
13	Q2132-2138	4,510	561.6	4,510	456
14	Q10264	4,300	561.6	4,300	456
15	AREF 81045934	589	561.6		
16	AREF 81460501	2,056	561.6		
17	AREF 82205457	4,531	561.6		
18	AREF 82206368	1,622	561.6		
19	AREF 82324247	824	561.6		
20	AREF 83020531	407	561.6		
21	**Generation Studies**				
22	GIQ0252	274	561.7	274	456
23	GIQ0397	6,949	561.7	6,949	456
24	GIQ0409	(90,815)	561.7	(90,815)	456
25	GIQ0564	412	561.7	412	456
26	GIQ0589	385	561.7	385	456
27	GIQ0627	8,517	561.7	8,517	456
28	GIQ0629	3,643	561.7	3,643	456
29	GIQ0634	10,252	561.7	10,252	456
30	GIQ0636	9,339	561.7	9,339	456
31	GIQ0641	13,058	561.7	13,058	456
32	GIQ0642	5,072	561.7	5,072	456
33	GIQ0647	134	561.7	134	456
34	GIQ0648	599	561.7	599	456
35	GIQ0649	209	561.7	209	456
36	GIQ0650	1,963	561.7	1,963	456
37	GIQ0651	966	561.7	966	456
38	GIQ0652	966	561.7	966	456
39	GIQ0653	1,121	561.7	1,121	456
40	GIQ0656	4,840	561.7	4,840	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 2016/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	AREF 83163541	733	561.6		
3	AREF 83205077	9,186	561.6		
4	AREF 817749198	1,706	561.6		
5		588	561.6		
6	Customer Studies Accruals	(2,773)	561.6		
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21	**Generation Studies**				
22	GIQ0659	557	561.7	557	456
23	GIQ0660	866	561.7	866	456
24	GIQ0661	925	561.7	925	456
25	GIQ0662	1,213	561.7	1,213	456
26	GIQ0663	137	561.7	137	456
27	GIQ0664	198	561.7	198	456
28	GIQ0666	1,196	561.7	1,196	456
29	GIQ0667	137	561.7	137	456
30	GIQ0668	198	561.7	198	456
31	GIQ0670	868	561.7	868	456
32	GIQ0671	5,164	561.7	5,164	456
33	GIQ0672	812	561.7	812	456
34	GIQ0677	1,561	561.7	1,561	456
35	GIQ0682	618	561.7	618	456
36	GIQ0684	6,478	561.7	6,478	456
37	GIQ0686	6,822	561.7	6,822	456
38	GIQ0687	38,426	561.7	38,426	456
39	GIQ0702	5,510	561.7	5,510	456
40	GIQ0703	1,977	561.7	1,977	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	GIQ0704	3,679	561.7	3,679	456
23	GIQ0706	28,484	561.7	28,484	456
24	GIQ0707	29,579	561.7	29,579	456
25	GIQ0708	34,924	561.7	34,924	456
26	GIQ0710	33,046	561.7	33,046	456
27	GIQ0711	37,529	561.7	37,529	456
28	GIQ0712	33,689	561.7	33,689	456
29	GIQ0713	35,894	561.7	35,894	456
30	GIQ0714	8,846	561.7	8,846	456
31	GIQ0715	29,537	561.7	29,537	456
32	GIQ0716	3,250	561.7	3,250	456
33	GIQ0718	52,791	561.7	52,791	456
34	GIQ0719	20,037	561.7	20,037	456
35	GIQ0720	39,385	561.7	39,385	456
36	GIQ0721	31,728	561.7	31,728	456
37	GIQ0722	10,500	561.7	10,500	456
38	GIQ0723	287	561.7	287	456
39	GIQ0724	9,062	561.7	9,062	456
40	GIQ0725	3,602	561.7	3,602	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	GIQ0726	22,096	561.7	22,096	456
23	GIQ0727	9,684	561.7	9,684	456
24	GIQ0728	13,551	561.7	13,551	456
25	GIQ0729	25,763	561.7	25,763	456
26	GIQ0730	19,866	561.7	19,866	456
27	GIQ0731	14,055	561.7	14,055	456
28	GIQ0732	19,632	561.7	19,632	456
29	GIQ0733	24,265	561.7	24,265	456
30	GIQ0734	14,303	561.7	14,303	456
31	GIQ0735	22,759	561.7	22,759	456
32	GIQ0736	33,646	561.7	33,646	456
33	GIQ0737	11,130	561.7	11,130	456
34	GIQ0738	13,241	561.7	13,241	456
35	GIQ0739	15,785	561.7	15,785	456
36	GIQ0740	7,752	561.7	7,752	456
37	GIQ0741	26,707	561.7	26,707	456
38	GIQ0742	4,684	561.7	4,684	456
39	GIQ0743	7,595	561.7	7,595	456
40	GIQ0744	4,962	561.7	4,962	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	GIQ0745	19,294	561.7	19,294	456
23	GIQ0746	2,287	561.7	2,287	456
24	GIQ0747	7,424	561.7	7,424	456
25	GIQ0748	2,095	561.7	2,095	456
26	GIQ0749	8,433	561.7	8,433	456
27	GIQ0750	10,878	561.7	10,878	456
28	GIQ0751	12,387	561.7	12,387	456
29	GIQ0752	12,803	561.7	12,803	456
30	GIQ0753	14,823	561.7	14,823	456
31	GIQ0754	12,117	561.7	12,117	456
32	GIQ0755	8,779	561.7	8,779	456
33	GIQ0756	758	561.7	758	456
34	GIQ0757	18,421	561.7	18,421	456
35	GIQ0758	9,068	561.7	9,068	456
36	GIQ0759	1,478	561.7	1,478	456
37	GIQ0760	237	561.7	237	456
38	GIQ0761	2,032	561.7	2,032	456
39	GIQ0762	8,065	561.7	8,065	456
40	GIQ0763	8,572	561.7	8,572	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	GIQ0764	17,179	561.7	17,179	456
23	GIQ0765	1,993	561.7	1,993	456
24	GIQ0766	2,212	561.7	2,212	456
25	GIQ0767	1,868	561.7	1,868	456
26	GIQ0768	2,163	561.7	2,163	456
27	GIQ0769	13,110	561.7	13,110	456
28	GIQ0770	14,993	561.7	14,993	456
29	GIQ0771	1,487	561.7	1,487	456
30	GIQ0772	1,426	561.7	1,426	456
31	GIQ0773	1,566	561.7	1,566	456
32	GIQ0774	1,835	561.7	1,835	456
33	GIQ0775	1,881	561.7	1,881	456
34	GIQ0776	2,634	561.7	2,634	456
35	GIQ0777	1,683	561.7	1,683	456
36	GIQ0778	1,240	561.7	1,240	456
37	GIQ0779	10,340	561.7	10,340	456
38	GIQ0780	5,635	561.7	5,635	456
39	GIQ0781	11,751	561.7	11,751	456
40	GIQ0782	4,050	561.7	4,050	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	GIQ0783	1,144	561.7	1,144	456
23	GIQ0784	950	561.7	950	456
24	GIQ0785	1,232	561.7	1,232	456
25	GIQ0786	1,754	561.7	1,754	456
26	GIQ0787	1,280	561.7	1,280	456
27	GIQ0788	1,020	561.7	1,020	456
28	GIQ0789	1,578	561.7	1,578	456
29	GIQ0790	1,176	561.7	1,176	456
30	GIQ0791	881	561.7	881	456
31	GIQ0792	8,043	561.7	8,043	456
32	GIQ0793	6,841	561.7	6,841	456
33	GIQ0794	4,400	561.7	4,400	456
34	GIQ0795	2,742	561.7	2,742	456
35	GIQ0796	1,654	561.7	1,654	456
36	GIQ0797	2,966	561.7	2,966	456
37	GIQ0798	1,412	561.7	1,412	456
38	GIQ0799	1,973	561.7	1,973	456
39	GIQ0800	2,392	561.7	2,392	456
40	GIQ0801	1,110	561.7	1,110	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 2016/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	GIQ0802	995	561.7	995	456
23	GIQ0803	1,616	561.7	1,616	456
24	GIQ0804	2,016	561.7	2,016	456
25	GIQ0805	2,084	561.7	2,084	456
26	GIQ0806	1,737	561.7	1,737	456
27	GIQ0807	1,399	561.7	1,399	456
28	GIQ0809	2,275	561.7	2,275	456
29	GIQ0810	1,620	561.7	1,620	456
30	GIQ0811	1,945	561.7	1,945	456
31	GIQ0812	1,354	561.7	1,354	456
32	GIQ0813	1,354	561.7	1,354	456
33	GIQ0814	1,061	561.7	1,061	456
34	GIQ0815	894	561.7	894	456
35	GIQ0816	969	561.7	969	456
36	GIQ0817	1,185	561.7	1,185	456
37	GIQ0818	578	561.7	578	456
38	GIQ0824	667	561.7	667	456
39	GIQ0825	995	561.7	995	456
40	GIQ0826	667	561.7	667	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	GIQ0827	400	561.7	400	456
23	GIQ0828	400	561.7	400	456
24	GIQ0829	481	561.7	481	456
25	GIQ0830	481	561.7	481	456
26	GIQ0832	191	561.7	191	456
27	GIQ0833	191	561.7	191	456
28	GIQ0834	191	561.7	191	456
29	GIQ0835	1,860	561.7	1,860	456
30	GIQ0836	618	561.7	618	456
31	GIQ0838	378	561.7	378	456
32	GIQ0839	378	561.7	378	456
33	GIQ0841	64	561.7	64	456
34	GIQ0843	205	561.7	205	456
35	GIQ0844	205	561.7	205	456
36	Pre-Application Studies - East	27,395	561.7	27,395	456
37	Pre-Application Studies - West	24,657	561.7	24,657	456
38	Q10264	(4,300)	561.7	(4,300)	456
39	Customer Studies Accruals	98,723	561.7	(23,364)	456
40					

Schedule Page: 231.1   Line No.: 5   Column: a

AREFS 83163541, 83163568, 83163576 and 83163584

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 2016/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	856,824	2,491,688	908	2,890,302	458,210
2	DSM Balancing Account - ID	908,075	4,512,348	908,431	5,157,139	263,284
3	DSM Balancing Account - UT	14,269,911	58,003,608	908,431	72,273,519	
4	DSM Balancing Account - WA	1,943,274	11,379,652	908	10,807,670	2,515,256
5	DSM Balancing Account - WY	323,788	8,193,505	908,431	4,785,934	3,731,359
6	Irrigation Load Control - OR		135,000	908	66,002	68,998
7	Deferred Excess Net Power Costs - CA	6,395,828	1,811,572	555	3,453,095	4,754,305
8	Deferred Excess Net Power Costs - ID	22,396,531	6,535,108	555	16,551,278	12,380,361
9	Deferred Excess Net Power Costs - UT	40,428,344	1,597,463	555,431	29,160,809	12,864,998
10	Deferred Excess Net Power Costs - WY	16,420,025	132,660	555	13,667,160	2,885,525
11	Deferred Excess RECs in Rates - UT	11,354,395		456,431	8,588,308	2,766,087
12	Deferred Excess RECs/SO2 in Rates - WY	613,882	7,527	456	621,409	
13	Deferred Excess RECs in Rates - WA	3,169,877		456,254	2,433,675	736,202
14	Deferred Income Tax Electric	436,870,019	3,922,095	282,283	19,951,122	420,840,992
15	Solar ITC Basis Adjustment Regulatory Asset	78,736	362	282,283	3,939	75,159
16	Tax Adj on Postretirement Benefits - OR (5)	1,788,655		410.1	894,329	894,326
17	Tax Revenue Requirement Adjustment - WY (4)	4,408			4,408	
18	Pension	473,328,654	50,058,186		32,443,693	490,943,147
19	Other Postretirement	25,768,508	9,564,857		886,736	34,446,629
20	Postemployment Costs	3,417,221			1,226,328	2,190,893
21	Powerdale Decommissioning - ID (10)	130,146		407.3	26,216	103,930
22	Carbon Plant Regulatory Asset - ID (6)	2,393,193		403	478,639	1,914,554
23	Carbon Plant Regulatory Asset - UT (6)	17,223,206		403	3,444,641	13,778,565
24	Carbon Plant Regulatory Asset - WY (6)	5,790,939		403	1,158,188	4,632,751
25	Carbon Plant Inventory Regulatory Asset		3,119,560			3,119,560
26	Depreciation Study Deferral - ID	3,258,921	1,744,856			5,003,777
27	Depreciation Study Deferral - UT (17)	1,984,669		403	128,043	1,856,626
28	Depreciation Study Deferral - WY (17)	6,853,959		403	442,191	6,411,768
29	Generating Plant Liquidated Damages - WY	1,352,992		930.2	54,288	1,298,704
30	Generating Plant Liquidated Damages - UT	630,000		930.2	35,000	595,000
31	Klamath Hydroelectric Relicensing Costs - UT (10)	26,170,339	1,148,142	404	4,483,442	22,835,039
32	Cholla Plant Transaction Costs (26)	1,486,166		557	938,632	547,534
33	Washington Colstrip Unit No. 3 (22)	265,319		456	52,188	213,131
34	Environmental Costs (10)	44,491,898	7,877,418	253,925	3,437,942	48,931,374
35	Asset Retirement Obligations Regulatory Difference	65,097,432	16,576,020			81,673,452
36	Unamortized Contract Values	110,071,947		242	12,153,325	97,918,622
37	Unrealized Loss on Derivative Contracts	132,542,310		175,244	59,718,088	72,824,222
38	Greenhouse Gas Allowance Compliance - CA	796,625	6,883,303	555	7,679,928	
39	Solar Feed-In Tariff Deferral - OR (1)	5,336,104	4,955,696		4,745,435	5,546,365
40	Solar Incentive Subscriber Program - UT	21,683	1,290,300			1,311,983
41	Renewable Portfolio Standards Compliance - CA	49,313	7,092	555	56,405	
42	Renewable Portfolio Standards Compliance		339,537			339,537
43	Deferred Intervenor Funding Grants - OR (1)	1,442,958	258,463	928	1,290,508	410,913

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 2016/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	Deferred Intervenor Funding Grants - CA	40,406	199			40,605
2	Deferred Intervenor Funding Grants - ID	26,865				26,865
3	Catastrophic Event Regulatory Asset - CA (1)		545,000		347,657	197,343
4	Alternative Rate for Energy (CARE) - CA	3,091	657,473			660,564
5	Deferred Overburden Cost - ID	303,336	1,397,981	501	1,440,142	261,175
6	Deferred Overburden Cost - WY	842,293	4,129,595	501	4,237,214	734,674
7	BPA Balancing Account - OR	1,939,461	1,427,225			3,366,686
8	Asset Sales Balancing Account - OR		465,377	421.1	182,475	282,902
9	Property Insurance Reserve - OR	474,686	7,448,507	924	7,068,568	854,625
10	Property Insurance Reserve - WY	122,561	138,538	924	261,099	
11	Misc. Regulatory Assets/Liabilities - OR	73,531	190,922			264,453
12	Depreciation Deferral - WA		6,648			6,648
13	Utah Mine Disposition	186,332,549	572,547		20,480,463	166,424,633
14	Preferred Stock Redemption Loss - WY (10)	233,459		407.3	28,442	205,017
15	Preferred Stock Redemption Loss - UT (10)	677,439		407.3	82,531	594,908
16	Preferred Stock Redemption Loss - WA (10)	108,762		407.3	13,318	95,444
17	Merwin Fish Collector Project - WA (1)	162,586			162,586	
18	Mobile Home Park Conversion - CA	1,729	8,541			10,270
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44	**TOTAL :**	1,679,069,828	219,534,571		360,494,449	1,538,109,950

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.

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, including Monsanto and Agrium net power cost components.

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 net power cost mechanisms being amortized.

Schedule Page: 232 Line No.: 11 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.: 12 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.: 13 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.: 17 Column: d

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

Schedule Page: 232 Line No.: 18 Column: a

Weighted average remaining life being amortized is 21 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.: 18 Column: d

Pensions are associated with labor and generally charged to operations and maintenance expense and construction work in progress. Pension curtailments for Oregon, California, Idaho and remeasurement date changes for Oregon, Utah and California are charged to Account 920, Administrative and general salaries.

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

Weighted average remaining life of portion being amortized is 21 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

Other postretirement measurement date changes for Oregon, Utah, California and Wyoming's share of settlement losses are charged to Account 920, Administrative and general salaries.

Schedule Page: 232 Line No.: 20 Column: a

Weighted average remaining life is five years.

Schedule Page: 232 Line No.: 20 Column: d

Other postemployment costs are associated with labor and generally charged to operations and maintenance expense and construction work in progress. Other postemployment remeasurements are charged to Account 228.3, Accumulated provision for pensions and benefits.

Schedule Page: 232 Line No.: 29 Column: a

Weighted average remaining life is 26 years.

Schedule Page: 232 Line No.: 30 Column: a

Weighted average remaining life is 17 years.

Schedule Page: 232 Line No.: 36 Column: a

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

Schedule Page: 232 Line No.: 37 Column: a

Weighted average remaining life is five years.

Schedule Page: 232 Line No.: 39 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.: 3 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: a

Weighted average remaining life is approximately two years for the net property, plant and equipment not considered probable of disallowance and for the portion of losses associated with the assets held for sale. Additionally, the weighted average remaining life is approximately five years for closure costs incurred to date considered probable of recovery.

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

Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting
Account 445, Other sales to public authorities
Account 501, Fuel
Account 506, Miscellaneous General Expenses

Schedule Page: 232.1 Line No.: 17 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 2016/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)	286,209		557	137,381	148,828
2	Lacomb Irrigation (24)	278,130		557	45,720	232,410
3	Bogus Creek (41)	994,160		557	41,280	952,880
4	Mead Phoenix Availability and					
5	Transmission Charge (50)	11,867,960		565	419,341	11,448,619
6	TGS Buyout (23)	63,183		557	15,474	47,709
7	Point-to-Point Transmission	1,412,872	82,336	142, 419	500	1,494,708
8	Hermiston Swap (40)	3,534,017		557	171,694	3,362,323
9	Oregon Prepaid REC Purchases					
10	for RPS Compliance (1)	11,950		555	11,950	
11	Deferred Coal Costs - Wyodak					
12	Settlement (22)	2,346,272		151	335,182	2,011,090
13	Deferred Coal Costs - Naughton					
14	Settlement (7)	1,376,154		151	1,376,154	
15	Deferred Colstrip Plant					
16	Costs (5)	25,000		501	25,000	
17	LT Lease Commissions Prepaid	300,283	66,739	931	137,875	229,147
18	Lake Side Maintenance Prepaid	5,147,854	7,008,891			12,156,745
19	Lake Side 2 Maintenance Prepaid	10,805,583	6,377,778	107	4,801,047	12,382,314
20	Chehalis Maintenance Prepaid	2,856,589	2,936,784			5,793,373
21	Currant Creek Maint. Prepaid	20,193,323	3,176,110	107	19,857,053	3,512,380
22	Lease Incentives	331,194	125,000	454	319,581	136,613
23	Credit Agreement Costs	1,396,981	668,899	427, 431	741,503	1,324,377
24	PCRB LOC/SBBPA Costs	142,490	4,500	427	117,825	29,165
25	PCRB Mode Conversion Costs	259,714		427	67,977	191,737
26	'94 Series Restruct. Costs (16)	549,568		189, 427	89,209	460,359
27	Deferred S-3 Shelf Regis. Costs	186,399	5,503			191,902
28	LT Prepaid IBEW 57 Pension					
29	Contribution	850,198	6,412		856,610	
30	BPA LT Transmission Prepaid	3,902,426	151,254	565	990,335	3,063,345
31	Emission Reduction Credits	306,510				306,510
32	Unamortized Contract Values		1,785,425			1,785,425
33	Sales of Electric Utility					
34	Facilities & Properties	711,003	370,618		932,037	149,584
35	IT Licenses and Maint. Prepaid	108,381		921, 923	47,658	60,723
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	70,244,403				61,472,266

Schedule Page: 233 Line No.: 17 Column: a

The weighted average remaining life of long-term prepaid lease commissions being amortized is one year.

Schedule Page: 233 Line No.: 22 Column: a

The weighted average remaining life is one year.

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

The weighted average remaining life is two years.

Schedule Page: 233 Line No.: 24 Column: a

The weighted average remaining life is one year.

Schedule Page: 233 Line No.: 25 Column: a

The weighted average remaining life is eight years.

Schedule Page: 233 Line No.: 29 Column: d

Pensions are associated with labor and generally charged to operations and maintenance expense and construction work in progress, including Account 228.3, Accumulated provision for pensions and benefits.

Schedule Page: 233 Line No.: 34 Column: d

Account 102, Electric plant purchased or sold
Account 421.1, Gain on disposition of property

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 2016/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	189,756,726	202,357,014
3	Derivative contracts and unamortized contract values	93,561,265	66,912,983
4	State carryforwards	68,772,466	69,101,510
5	Loss contingencies	56,218,611	
6	Asset retirement obligations	80,689,134	77,524,010
7	Other	117,213,002	125,963,826
8	TOTAL Electric (Enter Total of lines 2 thru 7)	606,211,204	541,859,343
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)	606,211,204	541,859,343

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	$ 29,935,861	$ 44,474,964
Other	87,277,141	81,488,862
	$117,213,002	$125,963,826

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 2016/Q4

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	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	6.00% Series		100.00	
16	7.00% 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				
23				
24				
25				
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42				

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 2016/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
5,930	593,000					15
18,046	1,804,600					16
						17
23,976	2,397,600					18
						19
						20
						21
						22
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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, 2016, 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 2016/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		
17		
18		
19		
20		
21		
22		
23		
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39		
40	TOTAL	1,102,063,956

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, 2016.

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 2016/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		
13		
14		
15		
16		
17		
18		
19		
20		
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	8.635% Series due October 1, 2016	18,750,000	
4	8.470% Series due October 1, 2017	19,609,000	
5	5.65% Series due July 15, 2018	500,000,000	3,067,221
6			905,000 D
7	5.50% Series due January 15, 2019	350,000,000	2,515,793
8			2,292,500 D
9	3.85% Series due June 15, 2021	400,000,000	3,007,139
10			744,000 D
11	2.95% Series due February 1, 2022	350,000,000	2,424,350
12			308,000 D
13	2.95% Series due February 1, 2022	100,000,000	254,129
14			-81,000 P
15	2.95% Series due June 1, 2023	300,000,000	1,859,352
16			900,000 D
17	3.60% Series due April 1, 2024	425,000,000	3,345,164
18			255,000 D
19	3.35% Series due July 1, 2025	250,000,000	2,121,421
20			320,000 D
21	7.70% Series due November 15, 2031	300,000,000	2,874,150
22			864,000 D
23	5.90% Series due August 15, 2034	200,000,000	1,892,365
24			722,000 D
25	5.25% Series due June 15, 2035	300,000,000	2,912,021
26			1,080,000 D
27	6.10% Series due August 1, 2036	350,000,000	2,907,881
28			1,141,000 D
29	5.75% Series due April 1, 2037	600,000,000	589,216
30			24,000 D
31	6.25% Series due October 15, 2037	600,000,000	5,127,281
32			750,000 D
33	TOTAL	7,192,699,000	76,839,200

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 2016/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
04/15/1992	10/01/2016	04/15/1992	10/01/2016		109,189	3
04/15/1992	10/01/2017	04/15/1992	10/01/2017	1,722,000	246,922	4
07/17/2008	07/15/2018	07/17/2008	07/15/2018	500,000,000	28,250,000	5
						6
01/08/2009	01/15/2019	01/08/2009	01/15/2019	350,000,000	19,250,000	7
						8
05/12/2011	06/15/2021	05/12/2011	06/15/2021	400,000,000	15,400,000	9
						10
01/06/2012	02/01/2022	01/06/2012	02/01/2022	350,000,000	10,325,000	11
						12
03/06/2012	02/01/2022	03/06/2012	02/01/2022	100,000,000	2,950,000	13
						14
06/06/2013	06/01/2023	06/06/2013	06/01/2023	300,000,000	8,850,000	15
						16
03/13/2014	04/01/2024	03/13/2014	04/01/2024	425,000,000	15,300,000	17
						18
06/19/2015	07/01/2025	06/19/2015	07/01/2025	250,000,000	8,375,000	19
						20
11/21/2001	11/15/2031	11/21/2001	11/15/2031	300,000,000	23,100,000	21
						22
08/24/2004	08/15/2034	08/24/2004	08/15/2034	200,000,000	11,800,000	23
						24
06/13/2005	06/15/2035	06/13/2005	06/15/2035	300,000,000	15,750,000	25
						26
08/10/2006	08/01/2036	08/10/2006	08/01/2036	350,000,000	21,350,000	27
						28
03/14/2007	04/01/2037	03/14/2007	04/01/2037	600,000,000	34,500,000	29
						30
10/03/2007	10/15/2037	10/03/2007	10/15/2037	600,000,000	37,500,000	31
						32
				7,093,197,000	359,474,830	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 2016/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	6.35% Series due July 15, 2038	300,000,000	2,290,333
2			1,671,000 D
3	6.00% Series due January 15, 2039	650,000,000	6,134,687
4			6,175,000 D
5	4.10% Series due February 1, 2042	300,000,000	2,737,911
6			987,000 D
7	8.53% Series C Medium-Term Notes due Dec. 16, 2021	15,000,000	115,202
8	8.375% Series C Medium-Term Notes due Dec. 31, 2021	5,000,000	38,400
9	8.26% Series C Medium-Term Notes due Jan. 7, 2022	5,000,000	33,243
10	8.27% Series C Medium-Term Notes due Jan. 10, 2022	4,000,000	30,594
11	8.05% Series E Medium-Term Notes due Sept. 1, 2022	15,000,000	131,471
12	8.07% Series E Medium-Term Notes due Sept. 9, 2022	8,000,000	70,118
13	8.12% Series E Medium-Term Notes due Sept. 9, 2022	50,000,000	438,238
14	8.11% Series E Medium-Term Notes due Sept. 9, 2022	12,000,000	105,177
15	8.05% Series E Medium-Term Notes due Sept. 14, 2022	10,000,000	87,648
16	8.08% Series E Medium-Term Notes due Oct. 14, 2022	26,000,000	208,198
17	8.08% Series E Medium-Term Notes due Oct. 14, 2022	25,000,000	200,190
18	8.23% Series E Medium-Term Notes due Jan. 20, 2023	5,000,000	37,914
19	8.23% Series E Medium-Term Notes due Jan. 20, 2023	4,000,000	30,331
20			-81,560 P
21	7.26% Series F Medium-Term Notes due July 21, 2023	27,000,000	246,981
22	7.26% Series F Medium-Term Notes due July 21, 2023	11,000,000	100,622
23	7.23% Series F Medium-Term Notes due Aug. 16, 2023	15,000,000	137,211
24	7.24% Series F Medium-Term Notes due Aug. 16, 2023	30,000,000	274,423
25	6.75% Series F Medium-Term Notes due Sept. 14, 2023	5,000,000	38,250
26	6.75% Series F Medium-Term Notes due Sept. 14, 2023	2,000,000	15,300
27	6.72% Series F Medium-Term Notes due Sept. 14, 2023	2,000,000	15,300
28	6.75% Series F Medium-Term Notes due Oct. 26, 2023	20,000,000	152,326
29	6.75% Series F Medium-Term Notes due Oct. 26, 2023	16,000,000	121,861
30	6.75% Series F Medium-Term Notes due Oct. 26, 2023	12,000,000	91,396
31	6.71% Series G Medium-Term Notes due Jan. 15, 2026	100,000,000	904,467
32	Subtotal - First Mortgage Bonds	6,737,359,000	68,661,215
33	TOTAL	7,192,699,000	76,839,200

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
07/17/2008	07/15/2038	07/17/2008	07/15/2038	300,000,000	19,050,000	1
						2
01/08/2009	01/15/2039	01/08/2009	01/15/2039	650,000,000	39,000,000	3
						4
01/06/2012	02/01/2042	01/06/2012	02/01/2042	300,000,000	12,300,000	5
						6
12/16/1991	12/16/2021	12/16/1991	12/16/2021	15,000,000	1,279,500	7
12/31/1991	12/31/2021	12/31/1991	12/31/2021	5,000,000	418,750	8
01/08/1992	01/07/2022	01/08/1992	01/07/2022	5,000,000	413,000	9
01/09/1992	01/10/2022	01/09/1992	01/10/2022	4,000,000	330,800	10
09/18/1992	09/01/2022	09/18/1992	09/01/2022	15,000,000	1,207,500	11
09/09/1992	09/09/2022	09/09/1992	09/09/2022	8,000,000	645,600	12
09/11/1992	09/09/2022	09/11/1992	09/09/2022	50,000,000	4,060,000	13
09/11/1992	09/09/2022	09/11/1992	09/09/2022	12,000,000	973,200	14
09/14/1992	09/14/2022	09/14/1992	09/14/2022	10,000,000	805,000	15
10/15/1992	10/14/2022	10/15/1992	10/14/2022	26,000,000	2,100,800	16
10/15/1992	10/14/2022	10/15/1992	10/14/2022	25,000,000	2,020,000	17
01/20/1993	01/20/2023	01/20/1993	01/20/2023	5,000,000	411,500	18
01/29/1993	01/20/2023	01/29/1993	01/20/2023	4,000,000	329,200	19
						20
07/22/1993	07/21/2023	07/22/1993	07/21/2023	27,000,000	1,960,200	21
07/22/1993	07/21/2023	07/22/1993	07/21/2023	11,000,000	798,600	22
08/16/1993	08/16/2023	08/16/1993	08/16/2023	15,000,000	1,084,500	23
08/16/1993	08/16/2023	08/16/1993	08/16/2023	30,000,000	2,172,000	24
09/14/1993	09/14/2023	09/14/1993	09/14/2023	5,000,000	337,500	25
09/14/1993	09/14/2023	09/14/1993	09/14/2023	2,000,000	135,000	26
09/14/1993	09/14/2023	09/14/1993	09/14/2023	2,000,000	134,400	27
10/26/1993	10/26/2023	10/26/1993	10/26/2023	20,000,000	1,350,000	28
10/26/1993	10/26/2023	10/26/1993	10/26/2023	16,000,000	1,080,000	29
10/26/1993	10/26/2023	10/26/1993	10/26/2023	12,000,000	810,000	30
01/23/1996	01/15/2026	01/23/1996	01/15/2026	100,000,000	6,710,000	31
				6,700,722,000	354,973,161	32
				7,093,197,000	359,474,830	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	Pollution Control Obligations - Secured by Pledged First Mortgage Bonds:		
2	Poll Ctrl Rev Refunding Bonds, Sweetwater County, WY, Series 1994	21,260,000	510,479
3	Poll Ctrl Rev Refunding Bonds, Converse County, WY, Series 1994	8,190,000	209,777
4	Poll Ctrl Rev Refunding Bonds, Emery County, UT, Series 1994	121,940,000	3,274,246
5	Poll Ctrl Rev Refunding Bonds, Carbon County, UT, Series 1994	9,365,000	206,519
6	Poll Ctrl Rev Refunding Bonds, Lincoln County, WY, Series 1994	15,060,000	422,858
7	Poll Ctrl Rev Refunding Bonds, Lincoln Cnty, WY, Series 1991	45,000,000	771,836
8	Poll Ctrl Revenue Bonds, City of Forsyth, MT, Series 1986	8,500,000	304,824
9	Environ. Imprvmnt Rev Bonds, Converse County, WY, Series 1995	5,300,000	132,043
10	Environ. Imprvmnt Rev Bonds, Lincoln County, WY, Series 1995	22,000,000	404,262
11	Subtotal Pollution Control Obligations - Secured by Pledged First Mortgage Bonds	256,615,000	6,236,844
12			
13	Pollution Control Obligations - Unsecured:		
14	Poll Ctrl Rev Refndng Bonds, City of Forsyth, MT, Series 1988	45,000,000	380,198
15	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Series 1988A	50,000,000	422,443
16	Poll Ctrl Rev Refndng Bonds, City of Gillette, WY, Ser. 1988	41,200,000	351,905
17	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1992A	9,335,000	167,524
18	Poll Ctrl Rev Refndng Bonds, Converse County, WY, Series 1992	22,485,000	242,163
19	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1992B	6,305,000	151,908
20	Environ. Imprvmnt Rev Bonds, Sweetwater County, WY, Series 1995	24,400,000	225,000
21	Subtotal - Pollution Control Obligations - Unsecured	198,725,000	1,941,141
22			
23	TOTAL ACCOUNT 221	7,192,699,000	76,839,200
24			
25	Reacquired Bonds: (Account 222)		
26			
27	Advances from Associated Companies: (Account 223)		
28			
29	Other Long-Term Debt: (Account 224)		
30			
31	Long-Term Debt Authorized but Unissued		
32			
33	TOTAL	7,192,699,000	76,839,200

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 2016/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
11/17/1994	11/01/2024	11/17/1994	11/01/2024	21,260,000	300,313	2
11/17/1994	11/01/2024	11/17/1994	11/01/2024	8,190,000	71,229	3
11/17/1994	11/01/2024	11/17/1994	11/01/2024	121,940,000	1,525,018	4
11/17/1994	11/01/2024	11/17/1994	02/18/2016		22,043	5
11/17/1994	11/01/2024	11/17/1994	11/01/2024	15,060,000	146,889	6
01/17/1991	01/01/2016	01/17/1991	01/01/2016		81	7
12/01/1986	12/01/2016	12/01/1986	12/01/2016		74,396	8
11/17/1995	11/01/2025	11/17/1995	11/01/2025	5,300,000	46,330	9
11/17/1995	11/01/2025	11/17/1995	11/01/2025	22,000,000	210,290	10
				193,750,000	2,396,589	11
						12
						13
01/01/1988	01/01/2018	01/01/1988	01/01/2018	45,000,000	577,050	14
01/01/1988	01/01/2017	01/01/1988	01/01/2017	50,000,000	419,899	15
01/01/1988	01/01/2018	01/01/1988	01/01/2018	41,200,000	334,567	16
09/29/1992	12/01/2020	09/29/1992	12/01/2020	9,335,000	117,064	17
09/29/1992	12/01/2020	09/29/1992	12/01/2020	22,485,000	276,897	18
09/29/1992	12/01/2020	09/29/1992	12/01/2020	6,305,000	80,319	19
12/14/1995	11/01/2025	12/14/1995	11/01/2025	24,400,000	299,284	20
				198,725,000	2,105,080	21
						22
				7,093,197,000	359,474,830	23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				7,093,197,000	359,474,830	33

Schedule Page: 256.2 Line No.: 5 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.: 23 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.: 23 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 during the year.

Schedule Page: 256.2 Line No.: 31 Column: a

PacifiCorp currently has an effective shelf registration statement filed with the United States Securities and Exchange Commission on Form S-3 to issue up to $1.325 billion additional 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, 2016), 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 by the counties of Emery, Utah; Carbon, Utah; Converse, Wyoming; Lincoln, Wyoming; Sweetwater, Wyoming; and Moffat, Colorado (total of $300,345,000 authorized and $166,450,000 available as of December 31, 2016) and authorization to borrow the proceeds of new pollution control revenue bonds issued 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 (total of $150,000,000 authorized and available as of December 31, 2016) is as follows:

- IPUC - Case No. PAC-E-08-05, Order No. 30606, dated August 4, 2008.
- OPUC - Docket No. UF-4250, Order No. 08-382, dated July 29, 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 2016/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)	762,510,394
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8	Other	121,404,353
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13	Other	1,306,879,433
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18	Other	28,740,446
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25	Other	1,467,788,648
26	State Tax Deductions	-30,374,888
27	Federal Tax Net Income	663,890,198
28	Show Computation of Tax:	
29		
30	Federal Income Tax at 35.00%	232,361,569
31	Provision to Return Adjustment	-8,357,383
32	Tax Reserve Changes	13,449
33	Tax Settlement	647,104
34	Renewable Energy Production Tax Credits	-66,817,070
35		
36	Federal Income Tax Accrual	157,847,669
37		
38		
39		
40		
41		
42		
43		
44		

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

Particulars (Details)	Amounts
Contribution in Aid of Construction	71,153,413
Regulatory Asset - REC Sales Deferral - UT	8,588,308
Regulatory Asset - REC Sales Deferral - WA	2,433,675
Regulatory Asset - REC Sales Deferral - WY	613,882
Regulatory Asset - WA Colstrip #3	52,188
Regulatory Liability - BPA Balancing Account - WA	1,120,640
Regulatory Liability - Deferred Excess NPC - OR	8,251,457
Regulatory Liability - Deferred Excess NPC - UT	4,840,097
Regulatory Liability - Deferred Excess NPC - WA	8,731,562
Regulatory Liability - Deferred Excess NPC - WY	3,186,133
Regulatory Liability - Depreciation Decrease - OR	1,038,665
Regulatory Liability - DSM Balance Reclass	4,404,501
Regulatory Liability - OR Direct Access 5 Year Opt Out	524,790
Regulatory Liability - Sale of REC - OR	650
Regulatory Liability - Sale of REC - UT	408,173
Regulatory Liability - Sale of REC - WY	523,321
Regulatory Liability - UT Home Energy Lifeline	316,781
Regulatory Liability - WA Accel Depreciation	2,801,877
Regulatory Liability - WA Low Energy Program	391,092
Transmission Service Deposits	123,914
Reimbursements	1,863,634
Unearned Joint Use Pole Contact Revenue	35,600
Total	$121,404,353

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

Particulars (Details)	Amounts
Fed/State Tax Expense	334,027,316
50% Meals and Entertainment	821,250
Accrued Bonus	200,000
Accrued Royalties	1,871,877
Avoided Costs	15,278,163
Bear River Settlement Agreement	106,557
Book Depreciation	760,803,372
Book Depreciation Allocated to Medicare and M&E	85,425
Capitalized Labor and Benefit Costs	402,542
Coal Pile Inventory Adjustment	500,581
Deferred Coal Costs - Naughton Contract Settlement	1,376,155
Deferred Revenue - Other	70,833
Environmental Liability - Regulated	3,211,981
Hermiston Swap	171,693
Hydro Relicensing Obligation	1,344,292
Inventory Reserve	305,796
Joseph Settlement	137,381
Lewis River Settlement Agreement	49,793
Lobbying Expenses	2,102,435
LT Incentive Plan	2,481,404
LT Prepaid IBEW 57 Pension Contribution	850,198
Medicare Subsidy	7,987,383
Miscellaneous Current and Accrued Liability	1,399,928
Penalties	15,595
Pension Liability UMWA Withdrawal Obligation	4,438,442
Prepaid Membership Fees	3,080,016
Prepaid Surety Bond	158,745
Prepaid Taxes - IPUC	81,704
Prepaid Water Rights	40,000

Regulatory Asset - Carbon Plant Decomm/Inventory - CA	52,048
Regulatory Asset - Carbon Plant Decomm/Inventory - WA	277,798
Regulatory Asset - Carbon Unrecovered Plant - ID	478,639
Regulatory Asset - Carbon Unrecovered Plant - UT	3,444,641
Regulatory Asset - Carbon Unrecovered Plant - WY	1,158,188
Regulatory Asset - Cholla Plant Transaction Costs	1,122,425
Regulatory Asset - Deferred Excess NPC - CA	1,641,523
Regulatory Asset - Deferred Excess NPC - ID	10,016,170
Regulatory Asset - Deferred Excess NPC - UT	27,563,345
Regulatory Asset - Deferred Excess NPC - WY '09 & After	13,534,499
Regulatory Asset - Deferred Intervenor Funding Grants - OR	1,032,044
Regulatory Asset - Deferred Overburden Costs - ID	42,161
Regulatory Asset - Deferred Overburden Costs - WY	107,619
Regulatory Asset - DSM - Noncurrent	15,669,270
Regulatory Asset - Depreciation Increase - UT	128,043
Regulatory Asset - Depreciation Increase - WY	442,191
Regulatory Asset - Environmental Costs - WA	49,913
Regulatory Asset - FAS 158 Pension Liability	33,267,071
Regulatory Asset - GHG Allowance Compliance Costs - CA	796,626
Regulatory Asset - Goodnoe Hills Settlement - WY	21,250
Regulatory Asset - Klamath Hydroelectric Relicensing Costs - UT	3,335,301
Regulatory Asset - Lake Side Settlement - WY	27,331
Regulatory Asset - Liquidated Damages - Naughton Unit #2 - WY	5,708
Regulatory Asset - Pension MMT - UT	283,176
Regulatory Asset - Post Employment Costs	1,226,328
Regulatory Asset - Post Merger Loss - Reacquired Debt	572,406
Regulatory Asset - Postretirement - CA	17,488
Regulatory Asset - Postretirement - OR	193,035
Regulatory Asset - Postretirement - UT	278,648
Regulatory Asset - Postretirement Settlement Loss	375,321
Regulatory Asset - Postretirement Settlement Loss CC - WY	22,244
Regulatory Asset - Powerdale Decommissioning - ID	26,216
Regulatory Asset - Preferred Stock Redemption - WY	28,442
Regulatory Asset - Preferred Stock Redemption Loss - UT	82,531
Regulatory Asset - Preferred Stock Redemption Loss - WA	13,318
Regulatory Asset - REC Sales Deferral - CA	49,313
Regulatory Asset - Tax Revenue Requirement Adj - WY	4,407
Regulatory Asset - Liquidated Damages - UT	35,000
Regulatory Asset - Merwin Project - WA	166,018
Regulatory Liability - ARO/Reg Diff - Trojan - WA Portion	8,448
Regulatory Liability - Blue Sky - CA	50,590
Regulatory Liability - Blue Sky - UT	2,151,203
Regulatory Liability - Blue Sky - WA	51,295
Regulatory Liability - Blue Sky - WY	80,145
Regulatory Liability - Contra-Carbon Decommmissioning - WY	535,226
Regulatory Liability - Energy Savings Assistance - CA	724,546
Regulatory Liability - Injuries & Damages Reserve - OR	3,562,162
Regulatory Liability - OR Energy Conservation Charge	944,486
Regulatory Liability - Property Insurance Reserve - ID	60,937
Regulatory Liability - Property Insurance Reserve - WY	211,272
Regulatory Liability - Solar Incentive Program - UT	2,014,911
Reserve for Bad Debts	139,320
TGS Buyout	15,474
Trapper Mine Contract Obligation	206,750
Utah Mine Disposition	32,613,041
Intercompany Adjustment	2,521,075
Total	$1,306,879,433

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

Particulars (Details)	Amounts
Fed/State Tax Expense - Interest	(146,973)
Book Fixed Asset Gain/Loss	(1,830,691)
Deferred Revenue - Lease Incentives	(106,311)
Dividend Received Deduction - Deferred Compensation	(187,822)
Investment Gain/Loss - Tax	(1,692)
MCI F.O.G. Wire Lease	(417)
Officer's Life Insurance	(5,802,438)
Regulatory Asset - Alt Rate for Energy Program (CARE) - CA	(657,473)
Regulatory Asset - BPA Balancing Account - OR	(1,427,225)
Regulatory Liability - BPA Balancing Account - ID	(13,004)
Regulatory Liability - Depreciation Decrease - WA	(274,982)
Regulatory Liability - GHG Allowance Revenues - CA	(306,548)
Trapper Mining Stock Basis	(132,979)
Equity Earnings in Subsidiaries	(17,851,891)
Total	$(28,740,446)

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

Particulars (Details)	Amounts
Accrued Final Reclamation	(1,281,561)
Accrued Retention	(2,500)
Accrued Severance	(431,953)
Accrued Vacation	(581,139)
Amortization NOPAs 99-00 RAR	(50,796)
Basis Intangible Difference	(304,497)
Capitalized Depreciation	(4,931,895)
Cholla SHL NOPA (Lease Amortization)	(227,265)
Contra Receivable from Joint Owners	(430,376)
Cost of Removal	(73,978,760)
CWIP Reserve	(394,527)
Debt AFUDC	(15,207,203)
Deferred Compensation Mark to Market Gain/Loss - Income Statement	(384,981)
Deferred Compensation	(1,364,961)
Deferred Revenue - Other	(114,471)
Deseret Settlement Receivable	(115,019)
Energy West Accrued Liabilities	(645,912)
Environmental Liability - Non-Regulated	(129,197)
Equity AFUDC - Temp	(27,254,684)
FAS 112 Book Reserve - Post Employment Benefits	(962,263)
FAS 158 Pension Liability	(19,248,547)
FAS 158 Postretirement Liability	(4,308,429)
FAS 158 SERP Liability	(1,231,046)
Federal Tax Depreciation	(910,975,456)
Federal Tax Fixed Asset Gain/Loss	(5,912,813)
Fuel Cost Adjustment	(2,634,272)
Income Tax Interest	(573,227)
Injuries & Damages Accrual - Cash Basis	(21,391,976)
Insurance Reserve	(6,386,531)
LT Incentive Plan Mark to Market Gain/Loss - Income Statement	(651,003)
N Umpqua Settlement Agreement	(329,362)
Non-deductible Postretirement Costs	(7,987,383)
Oregon Regulatory Asset/Regulatory Liability Consolidation	(1,445)
Pension/Retirement Accrual	(268,151)
Pre-1943 Preferred Stock Dividend - Deduction	(64,760)
Prepaid Taxes - OPUC	(71,425)
Prepaid Taxes - Property Taxes	(663,387)
Prepaid Taxes - UPSC	(437,298)

Qualified Production Activities Deduction	(25,541,142)
Regulatory Asset - CA Mobile Home Park Conversion	(8,541)
Regulatory Asset - Carbon Plant Decomm/Inventory	(3,449,406)
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 Intervenor Funding Grants - CA	(199)
Regulatory Asset - Depreciation Increase - ID	(1,744,857)
Regulatory Asset - DSM Balance Reclass	(4,404,501)
Regulatory Asset - Energy West Mining	(12,705,124)
Regulatory Asset - Environmental Costs	(4,489,389)
Regulatory Asset - FAS 158 Postretirement Liability	(6,137,965)
Regulatory Asset - Asset Sales Balancing Account - OR	(282,902)
Regulatory Asset - Postretirement Settlement Loss CC - UT	(372,012)
Regulatory Asset - RPS Compliance Purchases	(339,537)
Regulatory Asset - Solar Feed-In Tariff Deferral - OR	(210,261)
Regulatory Asset - Storm Damage Deferral - CA	(197,343)
Regulatory Asset - UT Subscriber Solar Program	(1,290,300)
Regulatory Liability - 50% Bonus Tax Depreciation - WY	(506,122)
Regulatory Liability - Blue Sky - ID	(5,189)
Regulatory Liability - Blue Sky - OR	(451,730)
Regulatory Liability - Property Insurance Reserve - OR	(379,938)
Regulatory Liability - Property Insurance Reserve - UT	(1,184,998)
Regulatory Liability - Solar Feed-in Tariff Deferral - CA	(312,936)
Regulatory Liability - Trojan Decommissioning	(131,950)
Repairs Deduction	(167,797,688)
Rogue River - Habitat Enhancement Liability	(38,743)
Tax Depletion - SRC	(31,569)
USA Power Litigation	(121,583,765)
Wasatch Workers Compensation Reserve	(61,724)
Western Coal Carrier Retiree Medical Accrual	(908,000)
Total	$(1,467,788,648)

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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.
Alamo 6 Solar Holdings, LLC
Alaska Gas Transmission Company, LLC
Allie Beth Allman Real Estate, Ltd
Apex Home Maintenance, LLC
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
BHES CSG Holdings, 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
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.
Denver Rental, LLC
Desert Valley Company
DG-SB Project Holdings, LLC
Edina Financial Services, Inc.
Edina Realty Insurance, LLC
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 Network Realty, Inc.
First Realty Group, Inc.
First Realty, Ltd
First Reserve Insurance, Inc.
First Weber Illinois, LLC
First Weber, Inc.
Florida Network LLC
Florida Network Property Management, LLC
For Rent, Inc.
FR Kingfisher Holdings II, LLC
FR Mariah Holdings II, LLC
FRTC, LLC
FSRI Holdings, Inc.
Geronimo Community Solar Gardens Holding Company, LLC
Geronimo Community Solar Gardens, LLC
Gilbraltar Title Services, 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 Agency, LLC
HomeServices Insurance, Inc.
HomeServices Northeast, LLC
HomeServices of Alabama, Inc.
HomeServices of America, Inc.
HomeServices of California, Inc.
HomeServices of Colorado, LLC
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.
HSW Affiliates Holding, LLC
Huff Commercial Group, LLC

Huff-Drees Realty, Inc.
IES Holding II LLC
IMO Company, Inc.
Imperial Magma 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
Kentwood City Properties, LLC
Kentwood Commercial, LLC
Kentwood DTC, LLC
Kentwood Real Estate Services, LLC
Kentwood, 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.
MES Holding LLC
MHC Investment Company
MHC, Inc.
Mid-America Referral Network, Inc.
MidAmerican Central California Transco LLC
MidAmerican Energy Company
MidAmerican Energy Machining Services LLC
MidAmerican Energy 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
NNGC Acquisition LLC
Norcon Holdings, Inc.
Northern Aurora Inc.
Northern Consolidated Power, Inc.
Northern Natural Gas Company
Novatus Texas Holdings, LLC
NRS Referral Services, LLC
NV Energy, Inc.
NVE Holdings, LLC
NVE Insurance Co, Inc.
NW Referral Services, LLC

PCG Agencies, Inc.
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 Projects Holding, 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.
Professional Referrals, Inc.
Pru-One, Inc.
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 Insurance, LLC
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 Felipe Energy Company
Saranac Energy Company, Inc.
SECI Holdings, Inc.
Semonin Realtors, Inc.
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 Kentwood Company at Cherry Creek, LLC
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.
A.E. Company, Inc.
AAA Aircraft Supply
Accra Manufacturing 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.
Aerocraft Heat Treating Co., Inc.
Aerospace Dynamics International, Inc.
Affiliated Agency Operations Co.
Affordable Housing Partners, Inc.
Aipcf V Chi Blocker, 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.
Alu-Forge, Inc.
American All Risk Insurance Services, Inc.
American Commercial Claims Administrators, Inc.
American Dairy Queen Corporation
American Employers Group, Inc.
AmGUARD Insurance Company
Andrews Laser Works Corporation
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.
Arcturus Manufacturing Corporation
Artform International Inc.
Astrex Electronics, Inc.
Astrex Holding Company

Atlanta International Insurance Company
Atlantic Precision, Inc.
AU Captive Risk Assurance Co.
AU Holding Company, Inc.
Avibank Manufacturing, 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.
Brittain Machine Inc.
Brooks Sports, Inc.
Brookwood Insurance Company
BTM Manufacturing LP
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.
Caledonian Alloys Inc.
California Insurance Company
Camp Manufacturing Company
Campbell Hausfeld Holdings. Inc.
Campbell Hausfeld/Scott Fetzer Company
Cannon Equipment LLC
Cannon Muskegon Corporation

Carefree/Scott Fetzer Company
Carlton Forge Works
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.
Compass Aerospace Northwest Inc.
Complementary Coatings Corporation
Composites Horizons LLC
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
Designed Metal Connections, Inc.
Dickson Testing Co., Inc.
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
Duracell Distributing Inc.
Duracell Manufacturing Co.
Duracell U.S. Operations Inc.

Dynamic Development, Inc.
EastGUARD Insurance Company
Eco Color Company
Ecodyne Corporation
ELIM/STAFF
Ellis & Watts Global Industries, Inc.
Elm Street Corporation
Empire Distributors of North Carolina, Inc.
Empire Distributors, Inc.
Environment One Corporation
Exacta Aerospace Inc.
Executive Jet Management, Inc.
Exsif Worldwide, Inc.
ExtruMed, Inc.
Faraday Capital Limited
Farrow Machine & Manufacturing Co Inc.
Fatigue Technology Inc.
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.
Fortner Aerospace Manufacturing 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)
FTI Manufacturing Inc.
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
Greenville Metals Inc.
GUARDco, Inc.
H. H. Brown Shoe Company, Inc.
H.J. Justin & Sons, Inc.
Hackney Ladish Inc.
Halex/Scott Fetzer Company
Hallmark Sweet, Inc.
Hamilton Aviation Inc.
Hawthorn Life International, Ltd.
HDS Redevelopment Corporation
HeatPipe Technology, Inc.
Helicomb International 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.
Howell Penncraft, Inc.
Huntington Alloys Corporation
IdeaLife Insurance Company
Illinois Insurance Company
Ingersoll Cutting Tool Company
Innovative Building Products, Inc.
Innovative Coatings Technology Corporation
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.
JL Fiber Services Inc.
Johns Manville China, Ltd.
Johns Manville Corporation
Johns Manville, Inc.
Jordan's Furniture, Inc.
Justin Belt Company, Inc.
Justin Boot Company
Justin Brands, Inc.
Justin Industries, Inc.
Kahn Ventures, Inc.
Karmelkorn Shoppes, Inc.
Ken's Spray Equipment, Inc.
Klune Holdings Inc.
Klune Industries Inc.
Kova Solutions, Inc.
L.A. Terminals, Inc.
Leesburg Yarn Mills, Inc.
Lipotec Group Corp.
LJ Aero Holdings Inc.
LJ Synch Holdings Inc.
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.
McWilliams Forge Company
Meadowbrook Meat Company, Inc.
Medical Protective Finance Corporation
Medical Protective Insurance Services, Inc.
MedPro Group, Inc.
MedPro Risk Retention Services, Inc.
Metalac Fasteners 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
Noranco Manufacturing (USA) Ltd.
NorGUARD Insurance Company
North American Casualty Co.
Northern States Agency, Inc.
Norvell Electronics, Inc.
Noveon Hilton Davis, Inc.
NSS Technologies 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.
PCC Flow Technologies Holdings Inc.
PCC Flow Technologies Inc.
PCC Rollmet Inc.
PCC Specialty Products Inc.
PCC Structurals Inc.
Penn Coal Land, Inc.
Pennsylvania Insurance Company
Perfection Hy-Test Company
Permaswage Holdings, Inc.
PFVT Development, Inc.
Pine Canyon Land Company
PJR Management, Inc.
Plasma Coating Corporation
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 Castparts Corp
Precision Founders Inc.
Precision MO Corp
Precision Steel Warehouse - Charlotte
Precision Steel Warehouse, Inc.
Press Forge Company
Primus International Holding Company
Primus International 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.
Progressive Incorporated
Promesa Health, Inc.
Protective Coating Inc.
QS Partners LLC
R.C. Willey Home Furnishings
Rabun Apparel, Inc.
Radnor Specialty Insurance Company
Railserve, Inc.
Railsplitter Holdings Corporation
Rathgibson Holding Co LLC
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.
Shultz Steel Company
SHX Flooring, Inc.
SidePlate Systems, Inc.
Smilemakers Canada Inc.
Smilemakers, Inc.
SN Management, Inc.
Soco West, Inc.
Somerset Services, Inc.
SOS Metals San Diego, LLC
SOS Metals, Inc.
Southern Energy Homes, Inc.
Southwest United Industries Inc.
Special Metals Corporation
Specialized Pipe Services, Inc.
Spectra Contract Flooring Puerto Rico, Inc.
SPS International Investment Company
SPS Technologies LLC
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.
Stratoflight
Synchronous Aerospace Group
Syrgis Holdings, Inc.
Taegutec Inc.
TBS USA, Inc.
Texas Honing 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 Duracell Company Inc.
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
THI Acquisition Inc.
TIMET Asia Inc.
TIMET Real Estate Corporation
Titanium Metals Corporation
TMCA International Inc.
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
University Swaging Corporation
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
Weaver Manufacturing Inc.
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.
Wyman Gordan Investment Castings Inc.
Wyman Gordon Company
Wyman Gordon Forgings Cleveland Inc.
Wyman Gordon Forgings Inc.
Wyman Gordon Pennsylvania LLC
Wyman SC Inc.
X-L-Co., Inc.
XTRA Companies, Inc.
XTRA Corporation
XTRA Finance Corporation
XTRA Intermodal, Inc.

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	Federal:					
2	Income	66,502		157,847,669	150,912,651	6,921,569
3	FICA	723,563	5,000	35,723,112	35,752,642	
4	Unemployment	-37,013		236,789	236,260	
5	Foreign Withholding Taxes	1,522,888				
6	Subtotal	2,275,940	5,000	193,807,570	186,901,553	6,921,569
7						
8	State:					
9						
10	Arizona:					
11	Property	1,824,992		3,664,096	3,657,040	
12	Income			-95,270	403,675	-498,945
13	Subtotal	1,824,992		3,568,826	4,060,715	-498,945
14						
15	California:					
16	Property			2,291,272	2,291,272	
17	Unemployment	-70		26,533	26,463	
18	Franchise-Income			2,134,663	2,393,072	-258,409
19	Use	58,400		121,479	170,889	
20	Local Franchise	1,244,516		1,298,156	1,226,334	
21	Subtotal	1,302,846		5,872,103	6,108,030	-258,409
22						
23	Colorado:					
24	Property	2,110,000		2,192,437	2,102,437	
25	Income			-136		-136
26	Subtotal	2,110,000		2,192,301	2,102,437	-136
27						
28	Idaho:					
29	Property	3,124,891		5,799,246	5,551,509	
30	Income			2,117,388	2,507,662	-390,274
31	KWh	15,140		44,759	44,225	
32	Unemployment	1,328		35,925	36,089	
33	Use	13,218		288,232	274,494	
34	Subtotal	3,154,577		8,285,550	8,413,979	-390,274
35						
36	Montana:					
37	Property	2,348,559		5,460,331	5,080,479	
38	Corporate License-Income			-107,299	-54,340	-52,959
39	Unemployment			378	378	
40	Energy License	62,000		214,983	216,983	
41	TOTAL	41,847,694	12,597,489	426,729,279	424,577,879	1,906,359

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
79,951		199,451,072			-41,603,403	2
689,033					35,723,112	3
-36,484					236,789	4
1,522,888						5
2,255,388		199,451,072			-5,643,502	6
						7
						8
						9
						10
1,832,048		3,664,096				11
		-14,515			-80,755	12
1,832,048		3,649,581			-80,755	13
						14
						15
		2,162,811			128,461	16
					26,533	17
		2,421,496			-286,833	18
8,990					121,479	19
1,316,338		1,298,156				20
1,325,328		5,882,463			-10,360	21
						22
						23
2,200,000		1,955,505			236,932	24
		-136				25
2,200,000		1,955,369			236,932	26
						27
						28
3,372,628		5,777,230			22,016	29
		2,502,924			-385,536	30
15,674		44,759				31
1,164					35,925	32
26,956					288,232	33
3,416,422		8,324,913			-39,363	34
						35
						36
2,728,411		5,460,331				37
		-72,747			-34,552	38
					378	39
60,000		214,983				40
42,398,601	12,903,355	425,846,027			883,252	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 2016/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	Wholesale Energy	44,000		152,601	154,601	
2	Subtotal	2,454,559		5,720,994	5,398,101	-52,959
3						
4	Nevada:					
5	Commerce Tax	10,000		31,184	24,942	
6	Subtotal	10,000		31,184	24,942	
7						
8	New Mexico:					
9	Property			22,087	22,087	
10	Income			122,560	15,050	107,510
11	Subtotal			144,647	37,137	107,510
12						
13	Oregon:					
14	Property		11,864,822	23,979,696	24,270,769	
15	Unemployment	46,369		1,442,029	1,439,343	
16	Excise-Income			11,747,958	12,693,784	-945,826
17	City of Portland-Income			53,507	43,458	10,049
18	Department of Energy		727,667	1,475,126	1,494,919	
19	Tri-Met	396,062		948,617	1,000,374	
20	Lane County			1,259	1,259	
21	Franchise	4,539,937		29,447,424	29,046,163	
22	Subtotal	4,982,368	12,592,489	69,095,616	69,990,069	-935,777
23						
24	Texas:					
25	Unemployment			234	234	
26	Subtotal			234	234	
27						
28	Utah:					
29	Property	729,731		72,351,881	72,373,158	
30	Income			15,135,838	18,122,058	-2,986,220
31	Unemployment	5,092		193,477	194,970	
32	Navajo Nation			1,208	1,208	
33	Use	459,962		3,212,088	3,397,402	
34	Subtotal	1,194,785		90,894,492	94,088,796	-2,986,220
35						
36	Washington:					
37	Property	11,250,000		9,539,701	10,789,701	
38	Unemployment	10,631		52,906	62,135	
39	Business & Occupation	2,390		26,281	24,790	
40	Public Utility	1,335,000		12,692,327	12,752,327	
41	TOTAL	41,847,694	12,597,489	426,729,279	424,577,879	1,906,359

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)	
42,000		152,601				1
2,830,411		5,755,168			-34,174	2
						3
						4
16,242		31,184				5
16,242		31,184				6
						7
						8
		22,087				9
		144,735			-22,175	10
		166,822			-22,175	11
						12
						13
	12,155,895	22,921,194			1,058,502	14
49,055					1,442,029	15
		13,959,990			-2,212,032	16
		62,064			-8,557	17
	747,460	1,475,126				18
344,305					948,617	19
					1,259	20
4,941,198		29,447,424				21
5,334,558	12,903,355	67,865,798			1,229,818	22
						23
						24
					234	25
					234	26
						27
						28
708,454		72,323,322			28,559	29
		17,758,609			-2,622,771	30
3,599					193,477	31
		1,208				32
274,648					3,212,088	33
986,701		90,083,139			811,353	34
						35
						36
10,000,000		9,241,559			298,142	37
1,402					52,906	38
3,881		26,281				39
1,275,000		12,692,327				40
42,398,601	12,903,355	425,846,027			883,252	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 2016/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	Natural Gas Use Tax	103,284		1,487,586	1,352,196	
2	Use	70,697		613,867	643,026	
3	Forest excise tax			24,459	24,459	
4	Subtotal	12,772,002		24,437,127	25,648,634	
5						
6	Wyoming:					
7	Property	7,558,796		16,203,823	15,660,709	
8	Wind Generation Tax	1,767,169		2,051,320	1,770,434	
9	Unemployment	2,746		78,722	79,646	
10	Franchise	274,900		2,008,258	1,988,258	
11	Use	139,621		1,779,917	1,747,635	
12	Annual Report			71,079	71,079	
13	Subtotal	9,743,232		22,193,119	21,317,761	
14						
15	State Other:	2,603				
16						
17	Miscellaneous:					
18	Goshute Possessory			25,020	25,020	
19	Sho-Ban Possessory			245,033	245,033	
20	Navajo Possessory	19,790		39,630	39,605	
21	Ute Possessory			39,261	39,261	
22	Crow Possessory			70,038	70,038	
23	Umatilla Possessory			66,534	66,534	
24	Subtotal	22,393		485,516	485,491	
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	41,847,694	12,597,489	426,729,279	424,577,879	1,906,359

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 2016/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)	
238,674					1,487,586	1
41,538					613,867	2
					24,459	3
11,560,495		21,960,167			2,476,960	4
						5
						6
8,101,910		16,104,178			99,645	7
2,048,055		2,051,320				8
1,822					78,722	9
294,900		2,008,258				10
171,903					1,779,917	11
		71,079				12
10,618,590		20,234,835			1,958,284	13
						14
2,603						15
						16
						17
		25,020				18
		245,033				19
19,815		39,630				20
		39,261				21
		70,038				22
		66,534				23
22,418		485,516				24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
42,398,601	12,903,355	425,846,027			883,252	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, Federal, 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.: 12 Column: f

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

Schedule Page: 262 Line No.: 12 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.: 16 Column: l

$126,974 Account 408.2, Taxes other than income taxes, other income and deductions
1,487 Account 589, Rents
$128,461

Schedule Page: 262 Line No.: 17 Column: l

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

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

Charged to same account as related goods.

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

$ 1,050 Account 408.2, Taxes other than income taxes, other income and deductions
235,882 Account 107, Construction work in progress
$236,932

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

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

Schedule Page: 262 Line No.: 29 Column: l

$ 1,075 Account 408.2, Taxes other than income taxes, other income and deductions
20,941 Account 107, Construction work in progress
$ 22,016

Schedule Page: 262 Line No.: 30 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.: 30 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.: 32 Column: l

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

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

Charged to same account as related goods.

Schedule Page: 262 Line No.: 38 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.: 38 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.: 39 Column: l

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

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

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

Schedule Page: 262.1 Line No.: 10 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.: 14 Column: l

$ 23,430	Account 408.2, Taxes other than income taxes, other income and deductions
126,911	Account 589, Rents
908,161	Account 107, Construction work in progress
$1,058,502	

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

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

Schedule Page: 262.1 Line No.: 16 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.: 16 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.: 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.: 19 Column: l

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

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.: 25 Column: l

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

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

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

Schedule Page: 262.1 Line No.: 30 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.: 30 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.: 31 Column: l

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

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

Charged to same account as related goods.

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

$ 37,622 Account 408.2, Taxes other than income taxes, other income and deductions
  260,520 Account 107, Construction work in progress
$ 298,142

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

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

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

Account 151, Fuel stock

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

Charged to same account as related goods.

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

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

Schedule Page: 262.2 Line No.: 7 Column: l

$ 3,788 Account 408.2, Taxes other than income taxes, other income and deductions
  15,134 Account 589, Rents
  80,723 Account 107, Construction work in progress
$ 99,645

Schedule Page: 262.2 Line No.: 9 Column: l

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

Schedule Page: 262.2 Line No.: 11 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%	20,324,195			411.4, 420	4,452,276	
6	30%	257,462			420	11,695	
7	Idaho	108,299			411.4, 420	10,698	
8	TOTAL	20,689,956				4,474,669	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11	Idaho	1,815,166	190	446,700	420	178,200	-39,394
12	Total Nonutility	1,815,166		446,700		178,200	-39,394
13							
14							
15							
16							
17							
18							
19							
20							
21							
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47							
48							

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 2016/Q4

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
15,871,919	38.82 and 30		5
245,767	24		6
97,601	38.82 and 30		7
16,215,287			8
			9
			10
2,044,272	30		11
2,044,272			12
			13
			14
			15
			16
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			21
			22
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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%	$20,003,128	-	$ -	411.4(1)	$4,334,949	$ -	$15,668,179	38.82
10%	321,067	-	-	420(2)	117,327	-	203,740	30
	$20,324,195		$ -		$4,452,276	$ -	$15,871,919	

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

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

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	$ 53,634	-	$ -	411.4(1)	$ 6,452	$ -	$ 47,182	38.82
Idaho	54,665	-	-	420(2)	4,246	-	50,419	30
	$ 108,299		$ -		$ 10,698	$ -	$ 97,601	

(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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/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	5,895,811	131	802,456		5,093,355
2	Reclamation Costs - Trapper Mine	5,860,476			211,795	6,072,271
3	Western Coal Carriers Benefits					
4	Obligation	11,791,000	131	908,000		10,883,000
5	Program Incentives	114,470	921	114,470		
6	Deferred Compensation Plans	9,671,098	131, 920	2,708,272	1,343,311	8,306,137
7	Long-Term Incentive Plan	8,484,695	426.5	587,502	3,068,906	10,966,099
8	Regulated Environmental					
9	Liabilities	22,938,098	131, 182.3	4,536,776	7,748,757	26,150,079
10	Non-Regulated Environmental					
11	Liabilities	2,222,843	131, 426.5	228,661	99,464	2,093,646
12	Unearned Joint Use Pole					
13	Contact	2,864,521	454	6,208,523	6,244,123	2,900,121
14	Misc. Security Deposits	3,400	131, 172	1,800	3,800	5,400
15	Lease Incentives	906,925	931	106,311		800,614
16	Cowlitz/Lewis River O&M (1)	120,418	539	291,546	293,362	122,234
17	Employee Housing Security Deposits	17,975	131, 545	4,275	5,200	18,900
18	Cogeneration Bonds-Sunnyside	413,417				413,417
19	Transmission Security Deposits	2,392,500	131	754,500		1,638,000
20	Transmission Service Deposits	234,282			123,914	358,196
21	MCI F.O.G. Wire Lease (1)	557,618	454	3,343,623	3,343,206	557,201
22	Unamortized Contract Values	97,918,622	242	9,110,134	1,785,425	90,593,913
23	Loss Contingency - USA Power	121,583,766	131	122,591,657	1,007,891	
24	Accrued Right-of-Way Obligations	2,550,482	566	505,500	1,768,105	3,813,087
25	Navajo Tribal Utility Authority					
26	Escrow	480,148	131	946,826	466,678	
27	Facility Use Fee (2)	95,833	456	50,000		45,833
28	Eagle Mountain Contract					
29	Liability (2)	4,107,880	555	2,603,805		1,504,075
30	Energy Supply Management					
31	Deferral	250,000	456	229,167	350,000	370,833
32	Deer Creek Accrued Royalties				3,547,353	3,547,353
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	301,476,278		156,633,804	31,411,290	176,253,764

Schedule Page: 269 Line No.: 13 Column: a

The weighted average remaining life is one year.

Schedule Page: 269 Line No.: 15 Column: a

The weighted average remaining life is eight years.

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 2016/Q4

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	285,986,998	23,398,385	2,392,006
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	285,986,998	23,398,385	2,392,006
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)	285,986,998	23,398,385	2,392,006
18	Classification of TOTAL			
19	Federal Income Tax	251,774,964	20,016,569	1,523,140
20	State Income Tax	34,212,034	3,381,816	868,866
21	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 2016/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
						306,993,377	4
							5
							6
							7
						306,993,377	8
							9
							10
							11
							12
							13
							14
							15
							16
						306,993,377	17
							18
						270,268,393	19
						36,724,984	20
							21

NOTES (Continued)

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	4,414,667,387	580,057,875	465,799,659
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	4,414,667,387	580,057,875	465,799,659
6	Nonutility			
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	4,414,667,387	580,057,875	465,799,659
10	Classification of TOTAL			
11	Federal Income Tax	3,913,838,011	488,380,217	387,589,122
12	State Income Tax	500,829,376	91,677,658	78,210,537
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 2016/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
653,619	653,619	182.3	12,627,237	182.3	2,679,167	4,518,977,533	2
							3
							4
653,619	653,619		12,627,237		2,679,167	4,518,977,533	5
							6
							7
							8
653,619	653,619		12,627,237		2,679,167	4,518,977,533	9
							10
579,306	579,306		10,541,888		1,783,885	4,005,871,103	11
74,313	74,313		2,085,349		895,282	513,106,430	12
							13

NOTES (Continued)

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 2016/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	639,634,358	35,015,081	75,601,640
4	Other	17,892,378	9,172,918	9,695,623
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	657,526,736	44,187,999	85,297,263
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)	657,526,736	44,187,999	85,297,263
20	Classification of TOTAL			
21	Federal Income Tax	578,903,244	39,122,329	75,313,779
22	State Income Tax	78,623,492	5,065,670	9,983,484
23	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 2016/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
35,103,755	62,379,675		24,898,683		39,048,246	585,921,442	3
9,124,337	8,155,245	190, 283	13,954,933	190, 283	12,831,957	17,215,789	4
							5
							6
							7
							8
44,228,092	70,534,920		38,853,616		51,880,203	603,137,231	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
44,228,092	70,534,920		38,853,616		51,880,203	603,137,231	19
							20
39,057,541	62,217,336		34,018,017		45,486,262	531,020,244	21
5,170,551	8,317,584		4,835,599		6,393,941	72,116,987	22
							23

NOTES (Continued)

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

Account 182.3, Other regulatory assets
Account 190, Accumulated deferred income taxes

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

Account 182.3, Other regulatory assets
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 2016/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 - UT				4,404,503	4,404,503
2	Oregon Energy Conservation Charge	2,342,401	131,232	26,490,248	27,434,735	3,286,888
3	Deferred Excess Net Power Costs - UT				4,840,097	4,840,097
4	Deferred Excess Net Power Costs - WA Hydro	132,174	182.3	141,321	9,147	
5	Deferred Excess Net Power Costs - WA				8,863,736	8,863,736
6	Deferred Excess Net Power Costs - WY				3,186,133	3,186,133
7	Deferred Excess RECs in Rates - UT				408,173	408,173
8	Deferred Excess RECs/SO2 in Rates - WY				523,321	523,321
9	Income Tax Reg. Liability - WA Flow Through	968,175	411.1	906,139		62,036
10	Investment Tax Credit Regulatory Liability	10,803,718	190	2,338,409	259	8,465,568
11	Tax on Bonus Depreciation - WY (1)	968,851	440,442	897,059	390,937	462,729
12	Greenhouse Gas Allowance Compliance - CA	718,381	456,555,419	11,292,335	10,985,788	411,834
13	Solar Feed-In Tariff Deferral - CA	1,530,061	440,442,444	312,936		1,217,125
14	Solar Incentive Program - UT	13,835,120	440,442,444,445	4,994,002	7,008,913	15,850,031
15	Renewable Portfolio Standards Compliance - OR	33,376			649	34,025
16	Utah Home Energy Lifeline	1,264,950	142	25,235	342,015	1,581,730
17	Washington Low Income Program	1,614,504	142	404,013	795,105	2,005,596
18	California Energy Savings Assistance Program		908	614,202	1,338,748	724,546
19	2013 FERC Rate True-up - OR	11,797,468			8,251,457	20,048,925
20	Asset Retirement Obligations Reg. Difference	7,427,115	230	2,007,237		5,419,878
21	BPA Balancing Account - WA	54,637			1,120,640	1,175,277
22	BPA Balancing Account - ID	3,643,237	440,442	23,528	10,523	3,630,232
23	Blue Sky - OR	2,998,214	440,442	2,188,982	1,737,252	2,546,484
24	Blue Sky - WA	206,954	440,442	134,741	186,036	258,249
25	Blue Sky - CA	180,416	440,442	21,237	71,827	231,006
26	Blue Sky - UT	4,589,446	440,442	846,254	2,997,457	6,740,649
27	Blue Sky - ID	157,316	440,442	59,224	54,035	152,127
28	Blue Sky - WY	484,045	440,442	117,508	197,654	564,191
29	Injuries & Damages Reserve - OR	5,219,979			3,562,162	8,782,141
30	Property Insurance Reserve - ID	494,674	924	52,607	113,544	555,611
31	Property Insurance Reserve - UT	4,287,834	924	3,337,234	2,152,236	3,102,836
32	Property Insurance Reserve - WY				88,711	88,711
33	Depreciation Deferral - OR	1,854,938			1,038,665	2,893,603
34	Depreciation Deferral - WA (1)	268,334	440,442,444	268,334		
35	Deferred Steam Accel. Depreciation - WA				2,801,877	2,801,877
36	Merwin Fish Collector Project - WA				3,432	3,432
37	Direct Access 5-Year Opt Out - OR (10)		442	1,006,205	1,530,995	524,790
38						
39						
40						
41	TOTAL	77,876,318		58,478,990	96,450,762	115,848,090

Schedule Page: 278 Line No.: 10 Column: a

Weighted average remaining life is 39 years.

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 2016/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	1,851,336,999	1,781,722,516
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,544,450,403	1,556,424,635
5	Large (or Ind.) (See Instr. 4)	1,428,765,000	1,435,608,671
6	(444) Public Street and Highway Lighting	20,068,906	19,942,747
7	(445) Other Sales to Public Authorities	21,985,292	16,902,061
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	4,866,606,600	4,810,600,630
11	(447) Sales for Resale	177,098,460	269,833,622
12	TOTAL Sales of Electricity	5,043,705,060	5,080,434,252
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	5,043,705,060	5,080,434,252
15	Other Operating Revenues		
16	(450) Forfeited Discounts	9,371,769	9,141,277
17	(451) Miscellaneous Service Revenues	5,643,618	5,531,248
18	(453) Sales of Water and Water Power	75,033	
19	(454) Rent from Electric Property	20,494,188	19,100,070
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	21,137,492	28,322,174
22	(456.1) Revenues from Transmission of Electricity of Others	100,653,551	92,780,346
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	157,375,651	154,875,115
27	TOTAL Electric Operating Revenues	5,201,080,711	5,235,309,367

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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
16,057,814	15,565,510	1,598,695	1,574,480	2
				3
16,856,945	17,261,893	205,329	201,691	4
20,924,472	21,402,658	33,258	33,305	5
141,491	140,686	3,470	3,496	6
337,215	270,465	2	3	7
				8
				9
54,317,937	54,641,212	1,840,754	1,812,975	10
6,640,965	8,889,451			11
60,958,902	63,530,663	1,840,754	1,812,975	12
				13
60,958,902	63,530,663	1,840,754	1,812,975	14

Line 12, column (b) includes $ 274,945,000 of unbilled revenues.

Line 12, column (d) includes 3,291,966 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:

	2016	2015
Account service charges - disconnects/reconnects/returned check charges	$ 4,337,678	$ 4,450,368
Customer contract flat rate billings	1,265,230	1,038,530

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:

	2016	2015
Amortization of California greenhouse gas allowance revenue	$ 11,196,617	$ 11,212,184
Wind-based ancillary services	10,840,910	9,683,694
Energy exchange credits	4,908,564	10,083,346
Flyash/by-product sales	4,323,364	5,099,321
Revenue from generation interconnection and transmission service request studies	1,244,979	1,077,939
Timber sales	727,541	(a)
Maintenance charges for work on transmission facilities	524,742	336,138
Steam sales	468,274	665,336
Phase shifting equipment fee from Western Electricity Coordinating Council	404,456	1,130,302
Service territory fixed cost recovery fee	351,447	317,733
Deferral of Oregon retail customers' allocated share of the incremental Open Access Transmission Tariff revenues associated with FERC Docket No. ER11-3643-000	(7,093,960)	(5,114,029)
Renewable energy credit sales, including amortization and deferrals	(7,116,003)	(6,901,286)
Power sale and exchange agreements	(a)	550,096

(a) Amount is less than $250,000.

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RESIDENTIAL SALES					
2	CALIFORNIA					
3	06CHCK000R-CA RES CHECK M			1		
4	06LNX00311 - LINE EXT 80%GTY		812			
5	06NETMT135 - RES NET MTR	1,178	137,880	221	5,330	0.1170
6	06OALT015R-OUTD AR LGT SR	285	83,249	311	916	0.2921
7	06RESD000D-RES SRVC	165,079	22,000,937	17,351	9,514	0.1333
8	06RESDDL06-CA LOW INCOME	112,830	15,090,056	11,186	10,087	0.1337
9	06RGNSV025-CA SMALL GEN	1,240	271,375	477	2,600	0.2189
10	06RESD0DM9 - MULTI FAMILY	162	16,249	7	23,143	0.1003
11	06RESD0DS8-MULT FAM SBMET	1,134	101,485	16	70,875	0.0895
12	06RESD00DN - RES SVC DEL NO	73,724	9,951,186	6,848	10,766	0.1350
13	REVENUE_ACCT ADJ		-1,645,230			
14	DSM REVENUE-RESIDENTIAL		1,755,548			
15	BLUE SKY REV-RESIDENTIAL		19,678			
16	SOLAR FEED-IN REVENUE		121,356			
17	UNBILLED REV - UNCOLLECTIBLE		1,000			
18	UNBILLED REVENUE	6,840	1,025,000			0.1499
19						
20	IDAHO					
21	07LNX00010-MNTHLY 80%GUAR		1,155			
22	07LNX00035-ADV 80%MO GUAR		2,154			
23	07NETMT135 - ID RES NET MTR	1,988	200,226	167	11,904	0.1007
24	07OALCO007-CUST OWN LIGHT	10	3,859	1	10,000	0.3859
25	07OALT07AR-SECURITY AR LG	97	40,300	122	795	0.4155
26	07RESD0001-RES SRVC	459,502	53,649,081	48,864	9,404	0.1168
27	07RESD0036-RES SRVC-OPTIO	208,460	21,069,190	12,476	16,709	0.1011
28	07RGNSV06A-LRG GEN SVC-RES	306	23,363	2	153,000	0.0763
29	07RGNSV23A-SM GEN SVC-RES	8,071	936,937	985	8,194	0.1161
30	REVENUE_ACCT ADJ		-364,717			
31	DSM REVENUE-RESIDENTIAL		1,892,920			
32	BLUE SKY REV-RESIDENTIAL		53,432			
33	UNBILLED REV - UNCOLLECTIBLE		-7,000			
34	UNBILLED REVENUE	34,214	3,557,000			0.1040
35						
36	OREGON					
37	01CHCK000R-RES CHECK MTR			1		
38	01COST0004 - 01RESD0004	4,842,357	289,273,265			0.0597
39	01COSTR023 RES GEN SRV CST	94,191	5,651,543			0.0600
40	01COSTR028, OR RES GEN SVC	43,218	2,602,794			0.0602
41	TOTAL Billed	54,127,172	4,894,019,840	1,840,754	29,405	0.0904
42	Total Unbilled Rev.(See Instr. 6)	190,765	30,521,000	0	0	0.1600
43	TOTAL	54,317,937	4,924,540,840	1,840,754	29,509	0.0907

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	01FXRENEWR - FIXED		-2			
2	01HABIT004 - 01RESD0004	44,674	2,630,846			0.0589
3	01HABTR023-RES GEN SVC HAB	174	10,779			0.0619
4	01LNX00102-LINE EXT 80% G		9,825			
5	01LNX00109-REF/NREF ADV +		4,458			
6	01LNX00300 - LINE EXT 80% GTY		188			
7	01LNX00311 - LINE EXT 80% GTY		232			
8	01NETMT135-NET METERING		1,637,576	3,752		
9	01NMTOU135-TOU NET METERING		12,552	21		
10	01OALTB15R-OUTD AR LGT RE	2,224	362,726	2,555	870	0.1631
11	01PTOU0004 - 01RESD0004	15,752	971,566			0.0617
12	01PTOU0005-01RESEV05T TOU	5	233			0.0466
13	01RENEW004 - 01RESD0004	318,137	18,392,266			0.0578
14	01RENWR023-RENEW USAGE	571	34,000			0.0595
15	01RESD0004-RES SRVC		286,567,470	487,137		
16	01RESD004T - RES TIME OPT		822,045	1,121		
17	01RESEV05T-ELECT VEHICLE		326	1		
18	01RGNSB023-SMALL GENERAL		7,172,026	16,933		
19	01RGNSB028 -GEN SVC > 30 KW		1,283,575	200		
20	01RNETM023-NET METER RES		141,719	56		
21	01UPPL000R-BASE SCH FALL			3		
22	01VIR04136-VOLUME INCENTIVE		368,107	463		
23	REVENUE ADJ - DEF NPC		-429,396			
24	REVENUE_ACCT ADJ		-2,110,813			
25	DSM REVENUE-RESIDENTIAL		14,934,257			
26	BLUE SKY REV-RESIDENTIAL		653,015			
27	SOLAR FEED-IN REVENUE		1,803,388			
28	UNBILLED REV - UNCOLLECTIBLE		-1,000			
29	UNBILLED REVENUE	120,767	15,260,000			0.1264
30						
31	UTAH					
32	08BLSKY01R-BLUESKY ENERGY		-4			
33	08CFR00001-MTH FACILITY S		835			
34	08CHCK000R-UT RES CHECK M			1		
35	08COOLKPRR -COOL KEEPER			99,383		
36	08LNX00001-MTHLY 80% GUAR		2,793			
37	08LNX00005-MTHLY MIN GUAR		396			
38	08LNX00013-80% MNTHLY MIN		24,234			
39	08LNX00108-ANN COST MTHLY		1,656			
40	08MHTP0006-MOBILE HOME &	11,554	885,121	8	1,444,250	0.0766
41	TOTAL Billed	54,127,172	4,894,019,840	1,840,754	29,405	0.0904
42	Total Unbilled Rev.(See Instr. 6)	190,765	30,521,000	0	0	0.1600
43	TOTAL	54,317,937	4,924,540,840	1,840,754	29,509	0.0907

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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
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1	08MHTP0023-MOBILE HOME &	120	9,626	1	120,000	0.0802
2	08NETMT135 - NET MTR	48,943	5,849,091	10,828	4,520	0.1195
3	08NMT03135-LOW INCOME RES	49	5,319	8	6,125	0.1086
4	08OALT007R-SECURITY AR LG	2,588	739,388	2,765	936	0.2857
5	08PTLD000R-POST TOP LIGHT	1	110	2	500	0.1100
6	08RESD0001-RES SRVC	6,425,562	717,255,319	735,335	8,738	0.1116
7	08RESD0002-RES SRVC-OPTIO	3,149	345,310	387	8,137	0.1097
8	08RESD0003-LIFELINE PRGRM	179,763	19,701,464	24,390	7,370	0.1096
9	08RGNSV006-GEN SRVC-RES	94,718	7,359,254	242	391,397	0.0777
10	08RGNSV023-GEN SRVC-RES	94,881	10,622,324	13,026	7,284	0.1120
11	08RGNSV06A-UT SM GEN SVC	9,721	834,818	25	388,840	0.0859
12	08RGNSV06B-UT SM GEN SVC	30	4,214	1	30,000	0.1405
13	08RNM06135 - UT NET MTR, GEN	1,392	138,229	8	174,000	0.0993
14	08RNM23135 - UT NET MTR, GEN	666	70,337	95	7,011	0.1056
15	08UPPL000R-BASE SCH FALL			4		
16	REVENUE ADJ - DEF NPC		13,865,997			
17	REVENUE_ACCT ADJ		-5,451,075			
18	DSM REVENUE-RESIDENTIAL		29,451,444			
19	BLUE SKY REV-RESIDENTIAL		702,357			
20	SOLAR FEED-IN REVENUE		1,883,729			
21	UNBILLED REV - UNCOLLECTIBLE		46,000			
22	UNBILLED REVENUE	23,210	2,478,000			0.1068
23						
24	WASHINGTON					
25	02LNX00109-REF/NREF ADV +		2,605			
26	02NETMT135 - WA RES NET MTR	5,029	501,095	462	10,885	0.0996
27	02OALTB15R-WA OUTD AR LGT	993	150,626	1,078	921	0.1517
28	02RESD0016-WA RES SRVC	1,413,531	133,293,557	101,402	13,940	0.0943
29	02RESD0017-BILL ASSISTANCE	62,028	5,807,396	4,540	13,663	0.0936
30	02RESD0018-WA 3 PHASE RES	2,107	218,004	85	24,788	0.1035
31	02RESD018X-WA 3 PHASE RES	345	34,922	16	21,563	0.1012
32	02RGNSB024-WA SM GEN SVC	20,871	2,463,039	3,471	6,013	0.1180
33	REVENUE ADJ - DEF NPC		1,058,271			
34	REVENUE_ACCT ADJ		-6,055,394			
35	DSM REVENUE-RESIDENTIAL		4,725,777			
36	BLUE SKY REV-RESIDENTIAL		110,987			
37	UNBILLED REV - UNCOLLECTIBLE		3,000			
38	UNBILLED REVENUE	66,880	6,846,000			0.1024
39						
40						
41	TOTAL Billed	54,127,172	4,894,019,840	1,840,754	29,405	0.0904
42	Total Unbilled Rev.(See Instr. 6)	190,765	30,521,000	0	0	0.1600
43	TOTAL	54,317,937	4,924,540,840	1,840,754	29,509	0.0907

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1	WYOMING					
2	05BLSKY01R-BLUESKY ENERGY		-2			
3	05LNX00102-LINE EXT 80% G		751			
4	05NETMT135 - EXP PARTIALREQ	1,338	162,669	152	8,803	0.1216
5	05OALT015R-OUTD AR LGT SR	864	121,133	1,018	849	0.1402
6	05RESD0002-WY RES SRVC	879,200	98,673,675	101,390	8,671	0.1122
7	05RGNSV025-WY SM GEN SVC	9,309	1,145,773	1,459	6,380	0.1231
8	09OALT207R-SECURITY AR LG		86	1		
9	REVENUE ADJ - DEF NPC		-68,513			
10	REVENUE_ACCT ADJ		-41,901			
11	DSM REVENUE-RESIDENTIAL		777,553			
12	DSM REVENUE-RES GEN SVC		13,965			
13	BLUE SKY REV-RESIDENTIAL		96,166			
14	UNBILLED REV - UNCOLLECTIBLE		11,000			
15	UNBILLED REVENUE	27,899	3,217,000			0.1153
16	05LNX00109-REF/NREF ADV +		603			
17	05RESD0002-WY RES SRVC	113,236	12,878,388	12,425	9,114	0.1137
18	05RGNSV025- SM GEN SVC-RES	428	71,903	133	3,218	0.1680
19	09OALT207R-SECURITY AR LG	71	17,676	85	835	0.2490
20	05NETMT135 - EXP PARTIAL REQ	285	34,461	23	12,391	0.1209
21	09RES00002			2		
22	09RESD0002			4		
23	DSM REVENUE-RESIDENTIAL		184,797			
24	DSM REVENUE-RES GEN SVC		986			
25	BLUE SKY REV-RESIDENTIAL		18,612			
26	UNBILLED REVENUE	-137	-14,000			0.1022
27						
28	LESS MULTIPLE BILLINGS			-126,838		
29						
30	TOTAL RESIDENTIAL SALES	16,057,814	1,851,336,999	1,598,695	10,044	0.1153
31						
32	COMMERCIAL SALES					
33	CALIFORNIA					
34	06GNSV0025-CA GEN SRVC	53,181	9,498,208	6,469	8,221	0.1786
35	06GNSV025F-GEN SRVC-< 20	863	169,444	85	10,153	0.1963
36	06GNSV0A32-GEN SRVC-20 KW	80,622	12,927,829	1,046	77,076	0.1604
37	06LGSV048T-LRG GEN SERV	31,172	3,371,795	9	3,463,556	0.1082
38	06NMT48135-CA GEN SVC NET	2,471	266,671	1	2,471,000	0.1079
39	06LGSV0A36-LRG GEN SRVC-O	64,156	8,706,109	157	408,637	0.1357
40	06LNX00102-LINE EXT 80% GTY		3,971			
41	TOTAL Billed	54,127,172	4,894,019,840	1,840,754	29,405	0.0904
42	Total Unbilled Rev.(See Instr. 6)	190,765	30,521,000	0	0	0.1600
43	TOTAL	54,317,937	4,924,540,840	1,840,754	29,509	0.0907

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1	06LNX00105-CNTRCT $ MIN G		3,775			
2	06LNX00109-REF/NREF ADV +		95,113			
3	06LNX00300 - 80% MTHLY MIN		722			
4	06LNX00311 - LINE EXT 80% GTY		17,297			
5	06NMT36135-G SVC NT ->100	2,259	313,819	4	564,750	0.1389
6	06OALT015N-OUTD AR LGT SR	660	195,172	479	1,378	0.2957
7	06RCFL0042-AIRWAY & ATHLE	164	37,966	36	4,556	0.2315
8	06NMT25135-CA GEN SVC NET	66	12,045	10	6,600	0.1825
9	06NMT32135-CA GEN SVC NET	674	125,479	13	51,846	0.1862
10	06LNX00110-REF/NREF ADV +		1,792			
11	REVENUE_ACCT ADJ		-1,096,878			
12	DSM REVENUE-COMMERCIAL		1,133,181			
13	BLUE SKY REV-COMMERCIAL		1,524			
14	SOLAR FEED-IN REVENUE		114,661			
15	UNBILLED REVENUE	1,485	239,000			0.1609
16						
17	IDAHO					
18	07CISH0019-COMM & IND SPA	4,806	431,609	95	50,589	0.0898
19	07GNSV0006-GEN SRVC-LRG P	235,865	19,886,222	1,003	235,160	0.0843
20	07GNSV0009-GEN SRVC-HI VO	41,261	2,698,737	2	20,630,500	0.0654
21	07GNSV0023-GEN SRVC-SML P	142,125	14,486,853	6,587	21,577	0.1019
22	07GNSV0035-GEN SRVCOPTION	898	76,499	2	449,000	0.0852
23	07GNSV006A-GEN SRVC-LRG P	24,624	2,237,499	181	136,044	0.0909
24	07GNSV023A-GEN SRVC-SML P	24,814	2,526,740	1,255	19,772	0.1018
25	07GNSV023F-GEN SRVC SML P	4	408	5	800	0.1020
26	07LNX00010-MNTHLY 80%GUAR		5,810			
27	07LNX00035-ADV 80%MO GUAR		217,767			
28	07LNX00040-ADV+REFCHG+80%		53,578			
29	07OALT007N-SECURITY AR LG	254	99,660	173	1,468	0.3924
30	07OALT07AN-SECURITY AR LG	10	3,940	10	1,000	0.3940
31	07LNX00312 - ID LINE EXT		24,045			
32	07NMT06135 - NET MTR - LG GEN	1,780	154,300	4	445,000	0.0867
33	07NMT23135 - NET MTR - SM GEN	1,003	88,539	21	47,762	0.0883
34	07LNX00015-ANNUAL 80%GUAR		751			
35	07LNX00311 - LINE EXT 80% GTY		27,741			
36	07LNX00300 - 80% MTHLY MIN		6,099			
37	REVENUE_ACCT ADJ		-214,593			
38	DSM REVENUE-COMMERCIAL		1,078,790			
39	BLUE SKY REV-COMMERCIAL		5,669	1		
40	UNBILLED REVENUE	13,937	1,202,000			0.0862
41	TOTAL Billed	54,127,172	4,894,019,840	1,840,754	29,405	0.0904
42	Total Unbilled Rev.(See Instr. 6)	190,765	30,521,000	0	0	0.1600
43	TOTAL	54,317,937	4,924,540,840	1,840,754	29,509	0.0907

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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	OREGON					
2	01COST0023, OR GEN SRV, COST	984,643	57,306,127			0.0582
3	01COST0048 - 01LGSV0048	907,439	44,338,916			0.0489
4	01COST023F - GEN SRV COST	2,860	177,059			0.0619
5	01COSTB023 - OR GEN SRV,	23,262	1,377,468			0.0592
6	01COSTL030 - OR LRG GEN SRV,	1,105,059	57,447,941			0.0520
7	01COSTS028, OR GEN SERV	1,894,258	114,268,242			0.0603
8	01GNSB0023, OR GEN SRV BPA		1,587,840	2,863		
9	01GNSB0028, OR GEN SRV BPA		2,014,352	304		
10	01GNSB023T - OR GEN SRV TOU		30,270	56		
11	01GNSV0023, GEN SRV < 30 KW		53,326,987	56,171		
12	01GNSV0028, GEN SRV > 30 KW		57,406,844	8,940		
13	01GNSV023F - GEN SRV - FLAT RA	10,360	1,641,056	765	13,542	0.1584
14	01GNSV023M - GEN SRV, MANUAL	160	14,739	2	80,000	0.0921
15	01GNSV023T, OR GEN SRV, TOU		161,759	199		
16	01HABT0023, OR HABITAT BLEND	2,814	166,668			0.0592
17	01HABTB023 - OR HABITAT BLEND	26	1,593			0.0613
18	01LGSB0030, GEN DEL SRV, > 200		939,194	21		
19	01LGSV0030 - LG GEN SRV > 1000		29,050,037	630		
20	01LGSV0048-1000KW AND OVR		16,849,563	90		
21	01LGSV048M-LRG GEN SRVC 1	58,872	3,691,026	1	58,872,000	0.0627
22	01LNX00100-LINE EXT 60% G		2,360			
23	01LNX00102-LINE EXT 80% G		514,572			
24	01LNX00103-LINE EXT 80% G		2,427			
25	01LNX00105-CNTRCT $ MIN G		13,548			
26	01LNX00109-REF/NREF ADV +		1,077,598			
27	01LNX00110-REF/NREF ADV +		12,224			
28	01LNX00311 - LINE EXT 80% GTY		178,121			
29	01LNX00120 - LINE EXT 60% GTY		306			
30	01LNX00300 - LINE EXT 80% GTY		201,683			
31	01LPRS047M-PART REQ SRVC	40,688	4,009,173	5	8,137,600	0.0985
32	01NM23T135-OR NET MTR TOU		35			
33	01NMT23135 - NET MTR GEN < 30		232,093	273		
34	01NMT28135 - NET MTR GEN > 30		1,175,220	156		
35	01NMT30135 -NET MTR GEN > 200		1,296,887	26		
36	01NMT48135-NET MTR GEN SVC =		365,453	3		
37	01OALT015N-OUTD AR LGT NR	5,451	807,121	2,833	1,924	0.1481
38	01OALTB15N-OUTD AR LGT NR	1,455	244,079	1,058	1,375	0.1678
39	01PTOU0023, OR GEN SRV, TOU	2,833	167,270			0.0590
40	01PTOUB023, OR GEN SRV, TOU	462	27,808			0.0602
41	TOTAL Billed	54,127,172	4,894,019,840	1,840,754	29,405	0.0904
42	Total Unbilled Rev.(See Instr. 6)	190,765	30,521,000	0	0	0.1600
43	TOTAL	54,317,937	4,924,540,840	1,840,754	29,509	0.0907

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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	01RCFL0054-REC FIELD LGT	1,423	140,665	104	13,683	0.0989
2	01RENW0023, OR RENW USAGE	9,007	535,873			0.0595
3	01RENWB023 - OR RENEWABLE	92	5,683			0.0618
4	01STDAY023 - DAY STD OFR SCH	3,054	160,185			0.0525
5	01STDAY028 - DAY STD OFF SCH	13,048	703,146			0.0539
6	01STDAY030 - STD DAY OFF SCH	4,487	209,359			0.0467
7	01VIR23136-VOL INC <=30KW		156,342	105		
8	01VIR28136-VOL INC >30KW		648,988	98		
9	01VIR30136-VOL INC >200KW		307,160	7		
10	01VIR48136-VOL INC >1000KW		127,245	1		
11	01LGSB0048 - LG GSVC > 1000		82,745	1		
12	01LGSV028M - LGSV, <1000 kW, M	419	39,976	1	419,000	0.0954
13	01GNSV0728 - GEN SVC DIR ACC		157,826	10		
14	01GNSV0730 -GEN SVC DIR ACC		2,277,912	18		
15	01GNSV0748 LG GEN SVC DIR		5,224,840	3		
16	REVENUE ADJ - DEF NPC		-322,734			
17	REVENUE_ACCT ADJ		-779,156			
18	DSM REVENUE-COMMERCIAL		10,013,396			
19	BLUE SKY REV-COMMERCIAL		941,521	101		
20	SOLAR FEED-IN REVENUE		1,519,379			
21	UNBILLED REVENUE	-66,183	-4,175,000			0.0631
22						
23	UTAH					
24	08ABL-NRES - APPLICANT BUILT		7,385			
25	08CFR00051-MTH FAC SRVCHG		38,958			
26	08CFR00052-ANN FAC SVCCHG		2			
27	08COOLKPRN - A/C DIRECT LOAD			2,109		
28	08GNSV0006-GEN SRVC-DISTR	4,982,089	421,564,259	11,125	447,828	0.0846
29	08GNSV0009-GEN SRVC-HI VO	665,283	38,823,800	33	20,160,091	0.0584
30	08GNSV0023-GEN SRVC-DISTR	1,217,086	121,957,443	70,373	17,295	0.1002
31	08GNSV006A-GEN SRVC-ENERG	269,664	31,929,816	2,150	125,425	0.1184
32	08GNSV006B-GEN SRVC-DEM&	5,118	524,598	31	165,097	0.1025
33	08GNSV006M-MNL DIST VOLTG	5,224	341,491	6	870,667	0.0654
34	08GNSV009A-GEN SRVC HI VO	21,682	1,501,397	2	10,841,000	0.0692
35	08GNSV023F-GEN SRVC FIXED	1,311	189,629	129	10,163	0.1446
36	08GNSV023M-GNSV DIST VOLT	157	13,804	5	31,400	0.0879
37	08GNSV06AM-MNL ENERGY TOD	219	29,354	1	219,000	0.1340
38	08GNSV06MN-GNSV DIST VOLT	34,920	2,765,910	583	59,897	0.0792
39	08LNX00002-MTHLY 80% GUAR		292,685			
40	08LNX00004-ANNUAL 80%GUAR		15,711			
41	TOTAL Billed	54,127,172	4,894,019,840	1,840,754	29,405	0.0904
42	Total Unbilled Rev.(See Instr. 6)	190,765	30,521,000	0	0	0.1600
43	TOTAL	54,317,937	4,924,540,840	1,840,754	29,509	0.0907

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1	08LNX00006-FIXD MTHLY MIN		3,518			
2	08LNX00014-80% MIN MNTHLY		1,518,560			
3	08LNX00017-ADV/REF&80%ANN		184,040			
4	08LNX00158-ANNUALCOST MTH		32,101			
5	08LNX00300 - LINE EXT 80% PLUS		143,302			
6	08LNX00310 - IRR 80% ANN MIN		60,823			
7	08LNX00312 UT IRG LINE EXT		14,886			
8	08NMT06135-NET MTR GEN SV	97,709	8,370,003	209	467,507	0.0857
9	08NMT08135 -NET MTR GEN SVC	77,691	5,584,197	9	8,632,333	0.0719
10	08NMT23135 - UT NET MTR, GEN	5,188	562,759	419	12,382	0.1085
11	08NMT6A135-NET MTR GEN SVC T	3,082	517,205	36	85,611	0.1678
12	08OALT007N-SECURITY AR LG	7,853	1,828,696	4,139	1,897	0.2329
13	08POLE0075-POLES W/LIGHT		226	2		
14	08PRSV031M-BKUP MNT&SUPPL	81,723	5,411,008	4	20,430,750	0.0662
15	08PTLD000N-POST TOP LIGHT	6	452	2	3,000	0.0753
16	08TOSS015F-TRAFFIC SIG NM	171	15,948	20	8,550	0.0933
17	08TOSS0015-TRAF & OTHER S	2,759	296,597	972	2,838	0.1075
18	08MONL0015-MTR OUTDONIGHT	16,380	1,179,270	491	33,360	0.0720
19	08LNX00311 - LINE EXT 80% GTY		360,063			
20	08GNSV0008 -GEN SVC TOU	895,391	67,344,677	131	6,835,046	0.0752
21	08GNSV008M -GEN SVC TOU	23,435	1,997,028	4	5,858,750	0.0852
22	REVENUE ADJ - DEF NPC		14,401,163			
23	REVENUE_ACCT ADJ		-4,644,360			
24	DSM REVENUE-COMMERCIAL		27,123,428			
25	BLUE SKY REV-COMMERCIAL		105,521			
26	SOLAR FEED-IN REVENUE		1,309,687			
27	UNBILLED REVENUE	-80,190	-5,174,000			0.0645
28						
29	WASHINGTON					
30	02GNSB0024-WA GEN SRVC DO	27,949	2,713,484	1,483	18,846	0.0971
31	02GNSB024F-GEN SRVC DOM/F	154	19,798	6	25,667	0.1286
32	02GNSB24FP-WA GEN SVC	190	74,425	80	2,375	0.3917
33	02GNSV0024-WA GEN SRVC	469,123	43,371,560	13,828	33,926	0.0925
34	02GNSV024F-WA GEN SRVC-FL	1,074	149,113	107	10,037	0.1388
35	02LGSB0036-LRG GEN SVC IRG	58,463	4,809,779	101	578,842	0.0823
36	02LGSV0036-WA LRG GEN SRV	750,628	60,017,523	872	860,812	0.0800
37	02LGSV048T-LRG GEN SRVC 1	183,993	13,371,075	35	5,256,943	0.0727
38	02LNX00102-LINE EXT 80% G		41,673			
39	02LNX00103-LINE EXT 80% G		150			
40	02LNX00105-CNTRCT $ MIN G		1,818			
41	TOTAL Billed	54,127,172	4,894,019,840	1,840,754	29,405	0.0904
42	Total Unbilled Rev.(See Instr. 6)	190,765	30,521,000	0	0	0.1600
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1	02LNX00109-REF/NREF ADV +		253,163			
2	02LNX00110-REF/NREF ADV +		26,767			
3	02LNX00112-YR INCURRED CH		669			
4	02LNX00300-LINE EXT 80% G		5,679			
5	02LNX00311 - LINE EXT 80% GTY		67,003			
6	02LNX00312 - WA IRG LINE EXT		7,432			
7	02OALT015N-WA OUTD AR LGT	1,518	214,489	791	1,919	0.1413
8	02OALTB15N-WA OUTD AR LGT	520	80,595	472	1,102	0.1550
9	02RCFL0054-WA REC FIELD L	277	25,612	28	9,893	0.0925
10	02RFNDCENT - CENTRALIA RFN		-1			
11	02NMT24135, NET MTR, WA	2,483	235,346	61	40,705	0.0948
12	02NMT36135-NET METER LG SVC	8,576	701,643	10	857,600	0.0818
13	02NMT48135-WA LG SVC NET	10,285	750,863	2	5,142,500	0.0730
14	REVENUE ADJ - DEF NPC		991,442			
15	REVENUE_ACCT ADJ		-5,282,153			
16	DSM REVENUE-COMMERCIAL		4,216,679			
17	BLUE SKY REV-COMMERCIAL		23,525	3		
18	UNBILLED REVENUE	-66,476	-5,151,000			0.0775
19						
20	WYOMING					
21	05CHCK000N-WY NRES CHECK			1		
22	05GNSV0025-WY GEN SRVC	221,344	22,318,400	17,745	12,474	0.1008
23	05GNSV0028-GEN SVC > 15 KW	865,019	75,954,764	3,281	263,645	0.0878
24	05GNSV025F-GEN SRVC-FL RA	999	160,143	175	5,709	0.1603
25	05LGSV0046-WY LRG GEN SRV	153,043	11,609,471	19	8,054,895	0.0759
26	05LGSV048T-LRG GENSRV TIM	12,334	899,708	1	12,334,000	0.0729
27	05LNX00100-LINE EXT 60% G		1,092			
28	05LNX00102-LINE EXT 80% G		1,270,131			
29	05LNX00103-LINE EXT 80% G		2,868			
30	05LNX00105-CNTRCT $ MIN G		5,800			
31	05LNX00109-REF/NREF ADV +		560,901			
32	05LNX00110-REF/NREF ADV +		8,766			
33	05LNX00114-TEMP SVC 12MO>		1,496			
34	05NMT25135 - NET MTR, GEN	380	36,145	25	15,200	0.0951
35	05NMT28135-NET MTR SM GEN	7,178	654,617	20	358,900	0.0912
36	05OALT015N-OUTD AR LGT SR	2,637	372,754	1,621	1,627	0.1414
37	05RCFL0054-WY REC FIELD L	706	51,326	55	12,836	0.0727
38	05LNX00300 - LINE EXT 80% GTY		158,593			
39	05LNX00311 - LINE EXT 80% GTY		76,648			
40	05LNX00312 - WY IRG LINE EXT		5,471			
41	TOTAL Billed	54,127,172	4,894,019,840	1,840,754	29,405	0.0904
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1	REVENUE ADJ - DEF NPC		-98,073			
2	REVENUE_ACCT ADJ		-24,521			
3	DSM REVENUE-SMALL		1,093,706			
4	DSM REVENUE-LARGE		49,980			
5	BLUE SKY REV-COMMERCIAL		6,181			
6	UNBILLED REVENUE	-46,510	-3,845,000			0.0827
7	05GNSV0025-WY GEN SRVC	30,673	3,070,949	2,372	12,931	0.1001
8	05GNSV0028-GEN SVC > 15 KW	91,482	8,006,846	387	236,388	0.0875
9	05GNSV025F-GEN SRVC-FL RA	199	25,593	33	6,030	0.1286
10	05LNX00102-LINE EXT 80% G		62,888			
11	05LNX00109-REF/NREF ADV +		188,520			
12	05LNX00110-REF/NREF ADV +		1,747			
13	05LNX00114-TEMP SVC 12MO>		488			
14	05NMT25135 - WY NET MTR, GEN	75	6,415	5	15,000	0.0855
15	05NMT28135-NET MTR SM GEN	414	37,396	2	207,000	0.0903
16	09OALT207N-SECURITY AR LG	273	58,832	138	1,978	0.2155
17	09MONL0213-WY MTR OUTDOOR	289	17,741	12	24,083	0.0614
18	05LNX00300 - LINE EXT 80%		6,582			
19	05LNX00311 - LINE EXT 80%		5,748			
20	DSM REVENUE-SMALL		123,221			
21	BLUE SKY REV-COMMERCIAL		511			
22	UNBILLED REVENUE	-1,441	-114,000			0.0791
23						
24	LESS MULTIPLE BILLINGS			-23,920		
25						
26	TOTAL COMMERCIAL SALES	16,856,945	1,544,450,403	205,329	82,097	0.0916
27						
28	INDUSTRIAL SALES					
29	CALIFORNIA					
30	06GNSV0025-CA GEN SRVC	645	118,336	89	7,247	0.1835
31	06GNSV0A32-GEN SRVC-20 KW	2,635	441,950	19	138,684	0.1677
32	06LGSV048T-LRG GEN SERV	44,525	4,924,044	8	5,565,625	0.1106
33	06LGSV0A36-LRG GEN SRVC-O	6,835	953,577	13	525,769	0.1395
34	REVENUE_ACCT ADJ		-176,008			
35	DSM REVENUE-INDUSTRIAL		182,786			
36	BLUE SKY REV-INDUSTRIAL		12			
37	SOLAR FEED-IN REVENUE		22,696			
38	UNBILLED REVENUE	-455	-55,000			0.1209
39						
40						
41	TOTAL Billed	54,127,172	4,894,019,840	1,840,754	29,405	0.0904
42	Total Unbilled Rev.(See Instr. 6)	190,765	30,521,000	0	0	0.1600
43	TOTAL	54,317,937	4,924,540,840	1,840,754	29,509	0.0907

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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	IDAHO					
2	07CFR00001-MTH FACILITY S		2,217			
3	07CISH0019-COMM & IND SPA	44	4,394	2	22,000	0.0999
4	07GNSV0006-GEN SRVC-LRG P	89,653	6,580,538	107	837,879	0.0734
5	07GNSV0009-GEN SRVC-HI VO	75,600	5,051,900	16	4,725,000	0.0668
6	07GNSV0023-GEN SRVC-SML P	14,208	1,386,991	317	44,820	0.0976
7	07GNSV0035-GEN SRVCOPTION	999	82,753	1	999,000	0.0828
8	07GNSV006A-GEN SRVC LG P	3,579	305,015	22	162,682	0.0852
9	07GNSV023A-GEN SRVC-SML P	2,071	220,055	144	14,382	0.1063
10	07GNSV023S-IDAHO TRAFFIC	4	609	1	4,000	0.1523
11	07LNX00108-ANN COST MTHLY		1,996			
12	07OALT007N-SECURITY AR LG	13	4,981	16	813	0.3832
13	07OALT07AN-SECURITY AR LG		240	1		
14	07SPCL0001	1,319,900	85,974,980	1	1,319,900,000	0.0651
15	07SPCL0002	109,469	7,006,866	1	109,469,000	0.0640
16	REVENUE_ACCT ADJ		-75,522			
17	DSM REVENUE-INDUSTRIAL		345,198			
18	UNBILLED REVENUE	26,453	1,165,000			0.0440
19						
20	OREGON					
21	01COST0023, GEN SRV CST BSD	18,466	1,078,716			0.0584
22	01COST0048 - 01LGSV0048	1,278,714	62,843,220			0.0491
23	01COST023F - GEN SRV CST-BSD	1	64			0.0640
24	01COSTB023 - GEN SRV, CST-BSD	166	9,344			0.0563
25	01COSTL030 - LRG GEN SRV, CST	196,692	10,265,074			0.0522
26	01COSTS028, OR GEN SERV	91,263	5,487,120			0.0601
27	01GNSB0023, OR GEN SRV, BPA		10,419	13		
28	01GNSB0028, OR GEN SRV, BPA		10,382	2		
29	01GNSV0023, OR GEN SRV, < 30		1,043,818	995		
30	01GNSV0028, OR GEN SRV > 30		3,545,210	441		
31	01GNSV023F - GEN SRV - FLT	2	690	2	1,000	0.3450
32	01GNSV023M - OR GEN SRV		311	1		
33	01GNSV023T, GEN SRV, TOU OPT		2,741	3		
34	01GNSV0748 LG GEN SVC DIR		2,785,201	4		
35	01LGSV0030 - LG G SRV > 1000		7,501,515	140		
36	01LGSV0048-1000KW AND OVR		24,234,180	82		
37	01LGSV048M-LRG GEN SRVC 1	106,711	7,444,224	3	35,570,333	0.0698
38	01LNX00102-LINE EXT 80% G		54,809			
39	01LNX00109-REF/NREF ADV +		1,204			
40	01LNX00300 - LINE EXT 80% GTY		17,144			
41	TOTAL Billed	54,127,172	4,894,019,840	1,840,754	29,405	0.0904
42	Total Unbilled Rev.(See Instr. 6)	190,765	30,521,000	0	0	0.1600
43	TOTAL	54,317,937	4,924,540,840	1,840,754	29,509	0.0907

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1	01LPRS047M-PART REQ SRVC	268,992	17,423,613	3	89,664,000	0.0648
2	01NMT23135 - NET MTR GEN < 30		3,431	4		
3	01NMT28135 - NET MTR GEN > 30		38,616	5		
4	01NMT30135 - NET MTR GEN > 200		58,233	2		
5	01OALT015N-OUTD AR LGT NR	283	40,773	127	2,228	0.1441
6	01OALTB15N-OR OUTD AR LGT	4	546	4	1,000	0.1365
7	01PTOU0023, GEN SRV, TOU ENG	41	2,596			0.0633
8	01RENW0023, RENW USAGE SPLY	81	4,603			0.0568
9	01STDAY028 - DAY STD OFF SCH	170	9,159			0.0539
10	01VIR23136-VOL INC <=30KW		1,210	1		
11	01VIR28136-VOL INC >30 KW		13,962	2		
12	01VIR30136-VOL INC >200KW		37,768	1		
13	REVENUE ADJ - DEF NPC		-106,662			
14	REVENUE_ACCT ADJ		-1,192,390			
15	DSM REVENUE-INDUSTRIAL		834,548			
16	BLUE SKY REV-INDUSTRIAL		594,092	35		
17	SOLAR FEED-IN REVENUE		1,008,689			
18	UNBILLED REVENUE	39,953	4,514,000			0.1130
19						
20	UTAH					
21	08CFR00051-MTH FAC SRVCHG		18,561			
22	08EFOP0021-ELEC FURNACE O	1,471	165,987	2	735,500	0.1128
23	08EFOP021M-ELEC FURNACE O	962	158,719	2	481,000	0.1650
24	08GNSV0006-GEN SRVC-DISTR	655,080	57,474,508	1,032	634,767	0.0877
25	08GNSV0009-GEN SRVC-HI VO	3,326,730	186,910,163	114	29,181,842	0.0562
26	08GNSV0023-GEN SRVC-DISTR	54,472	5,540,520	3,298	16,517	0.1017
27	08GNSV006A-GEN SRVC-ENERG	65,544	7,699,193	261	251,126	0.1175
28	08GNSV006B-GEN SRVC-DEM&	121	9,984	1	121,000	0.0825
29	08GNSV009A-GEN SRVC HI VO	14,967	1,367,625	6	2,494,500	0.0914
30	08GNSV009M-MANL HIGH VOLT	436,435	24,470,061	10	43,643,500	0.0561
31	08GNSV023F-GEN SRVC FIXED	4	2,572	1	4,000	0.6430
32	08GNSV06MN-GNSV DIST VOLT	1,355	117,186	24	56,458	0.0865
33	08GNSV09AM-MAN TOD HIVOLT	1,385	169,753	1	1,385,000	0.1226
34	08LNX00002-MTHLY 80% GUAR		606,211			
35	08LNX00014-80% MIN MNTHLY		16,085			
36	08LNX00311 - LINE EXT 80% GTY		1,452			
37	08LNX00300 - LINE EXT 80% PLUS		65,412			
38	08LNX00310 - IRR 80% ANN MIN		4,173			
39	08OALT007N-SECURITY AR LG	1,160	248,931	438	2,648	0.2146
40	08TOSS0015-TRAF & OTHER S	9	1,321	9	1,000	0.1468
41	TOTAL Billed	54,127,172	4,894,019,840	1,840,754	29,405	0.0904
42	Total Unbilled Rev.(See Instr. 6)	190,765	30,521,000	0	0	0.1600
43	TOTAL	54,317,937	4,924,540,840	1,840,754	29,509	0.0907

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1	08MONL0015-MTR OUTDONIGHT	16	2,448	6	2,667	0.1530
2	08NMT06135-NET MTR GEN SV	2,260	207,659	6	376,667	0.0919
3	08NMT23135 -NET MTR G <25	157	16,844	12	13,083	0.1073
4	08NMT6A135-NET MTR GEN SVC T	3,738	518,893	10	373,800	0.1388
5	08PRSV031M-BKUP MNT&SUPPL	21,585	1,895,372	2	10,792,500	0.0878
6	08SPCL0001	567,236	29,742,630	1	567,236,000	0.0524
7	08SPCL0002	1,014,177	45,819,520	1	1,014,177,000	0.0452
8	08SPCL0003	938,861	49,785,690	1	938,861,000	0.0530
9	08GNSV06AM-MNL ENERGY TOD	244	32,179	2	122,000	0.1319
10	08GNSV0008 - GEN SVC TOU	942,351	71,924,436	95	9,919,484	0.0763
11	08GNSV008M - GEN SVC TOU	44,711	3,521,853	6	7,451,833	0.0788
12	REVENUE ADJ - DEF NPC		8,897,132			
13	REVENUE_ACCT ADJ		-4,164,720			
14	DSM REVENUE-INDUSTRIAL		13,766,171			
15	BLUE SKY REV-INDUSTRIAL		38,376	8		
16	SOLAR FEED-IN REVENUE		1,633,391			
17	UNBILLED REVENUE	33,459	3,456,000			0.1033
18						
19	WASHINGTON					
20	02GNSB0024-WA GEN SRVC DO	1,033	108,183	46	22,457	0.1047
21	02GNSB24FP-WA GEN SVC	4	1,727	1	4,000	0.4318
22	02GNSV0024-WA GEN SRVC	15,204	1,426,093	330	46,073	0.0938
23	02GNSV024F-WA GEN SRVC-FL	33	8,572	4	8,250	0.2598
24	02LGSV0036-WA LRG GEN SRV	99,781	8,290,853	101	987,931	0.0831
25	02LGSV048T-LRG GEN SRVC 1	646,631	41,442,827	31	20,859,065	0.0641
26	02LNX00103-LINE EXT 80% G		40,490			
27	02OALT015N-WA OUTD AR LGT	104	13,732	38	2,737	0.1320
28	02OALTB15N-WA OUTD AR LGT	27	4,043	14	1,929	0.1497
29	02PRSV47TM-LRG PART REQMT	1,597	287,631	1	1,597,000	0.1801
30	02LGSB0036-LRG GEN SVC IRG	1,462	193,809	11	132,909	0.1326
31	REVENUE ADJ - DEF NPC		528,733			
32	REVENUE_ACCT ADJ		-2,205,953			
33	DSM REVENUE-INDUSTRIAL		1,745,930			
34	UNBILLED REVENUE	14,392	1,197,000			0.0832
35						
36	WYOMING					
37	05GNSV0025-WY GEN SRVC	19,225	1,836,035	1,164	16,516	0.0955
38	05GNSV0028-GEN SVC > 15 KW	239,015	18,705,301	472	506,388	0.0783
39	05GNSV025F-GEN SRVC-FL RA	26	4,295	8	3,250	0.1652
40	05LGSV0046-WY LRG GEN SRV	1,615,452	111,001,957	60	26,924,200	0.0687
41	TOTAL Billed	54,127,172	4,894,019,840	1,840,754	29,405	0.0904
42	Total Unbilled Rev.(See Instr. 6)	190,765	30,521,000	0	0	0.1600
43	TOTAL	54,317,937	4,924,540,840	1,840,754	29,509	0.0907

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1	05LGSV046M-WY LRG GEN SRV	11,699	885,298	1	11,699,000	0.0757
2	05LGSV048M-TOU>1000KW MAN	273,912	16,673,768	1	273,912,000	0.0609
3	05LGSV048T-LRG GENSRV TIM	1,710,573	101,065,367	11	155,506,636	0.0591
4	05LNX00100-LINE EXT 60% G		63,483			
5	05LNX00102-LINE EXT 80% G		1,146,531			
6	05LNX00103-LINE EXT 80% G		-5,948			
7	05LNX00105-CNTRCT $ MIN G		42,239			
8	05LNX00109-REF/NREF ADV +		291,635			
9	05LNX00110-REF/NREF ADV +		283			
10	05LNX00300 - LINE EXT 80%		92,199			
11	05LNX00311 - LINE EXT 80%		24,193			
12	05OALT015N-OUTD AR LGT SR	77	9,755	38	2,026	0.1267
13	05PRSV033M-PART SERV REQ	1,232,040	85,062,668	8	154,005,000	0.0690
14	REVENUE ADJ - DEF NPC		-459,678			
15	REVENUE_ACCT ADJ		116,966			
16	DSM REVENUE-SMALL		225,620			
17	DSM REVENUE-LARGE		1,257,553			
18	BLUE SKY REV-INDUSTRIAL		-3,984			
19	UNBILLED REVENUE	44,252	3,537,000			0.0799
20	05GNSV0025-WY GEN SRVC	8,498	740,517	290	29,303	0.0871
21	05GNSV0028-GEN SVC > 15 KW	48,039	3,728,964	71	676,606	0.0776
22	05GNSV028M-GEN SVC > 15 KW	4,379	276,172	3	1,459,667	0.0631
23	05LGSV0046-WY LRG GEN SRV	38,724	2,820,607	3	12,908,000	0.0728
24	05LGSV048M-TOU>1000KW MAN	216,747	13,578,041	3	72,249,000	0.0626
25	05LGSV048T-LRG GENSRV TIM	1,212,174	77,709,839	13	93,244,154	0.0641
26	05LNX00102-LINE EXT 80% G		312,414			
27	05LNX00109-REF/NREF ADV +		2,134,795			
28	05LNX00300 - LINE EXT 80%		1,649			
29	05PRSV033M-PART SERV REQ	96,485	6,152,519	2	48,242,500	0.0638
30	09OALT207N-SECURITY AR LG	5	899	3	1,667	0.1798
31	DSM REVENUE-SMALL		52,005			
32	DSM REVENUE-LARGE		399,576			
33	BLUE SKY REV-INDUSTRIAL		23			
34	UNBILLED REVENUE	7,353	615,000			0.0836
35						
36	LESS MULTIPLE BILLINGS			-934		
37						
38	TOTAL INDUSTRIAL SALES	19,385,150	1,279,414,294	9,771	1,983,947	0.0660
39						
40						
41	TOTAL Billed	54,127,172	4,894,019,840	1,840,754	29,405	0.0904
42	Total Unbilled Rev.(See Instr. 6)	190,765	30,521,000	0	0	0.1600
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1	IRRIGATION SALES					
2	CALIFORNIA					
3	06APSV0020-AG PMP SRVC	12,397	1,762,946	768	16,142	0.1422
4	06APSV0115-CA AGRI PUMP TOU	246	23,975	2	123,000	0.0975
5	06APSV020L-AG PMP SRVC-NO	53,695	7,953,897	591	90,854	0.1481
6	06APSV115L-CA AGRI PUMP TOU,	784	95,574	6	130,667	0.1219
7	06LGSV048T-LRG GEN SERV	2,682	305,916	1	2,682,000	0.1141
8	06LNX00103-LINE EXT 80% G		2,418			
9	06LNX00109-REF/NREF ADV +		509			
10	06LNX00110-REF/NREF ADV +		29,452			
11	06LNX00310-80% ANN MIN + 80%		5,448			
12	06LNX00312 - CA IRG LINE EXT		30,328			
13	06NML20135-AGRI PUMP-NET MTR	498	100,434	9	55,333	0.2017
14	06NMT20135-AGRI PUMP-NET	24	3,800	1	24,000	0.1583
15	06USBR0020-KLAM IRG ONPRJ	2,998	527,432	276	10,862	0.1759
16	06USBR0115-CA AGR PMP TOU	38	4,769	1	38,000	0.1255
17	06USBR020L-KLAM IRG PRJ-NO	17,066	2,839,748	360	47,406	0.1664
18	06USBR115L-CA AGR PMP TOU	767	102,696	7	109,571	0.1339
19	REVENUE_ACCT ADJ		-478,695			
20	DSM REVENUE-IRRIGATION		509,920			
21	BLUE SKY REV-IRRIGATION		23			
22	SOLAR FEED-IN REVENUE		52,642			
23	UNBILLED REVENUE	-16	-8,000			0.5000
24						
25	IDAHO					
26	07APSA010L - IRG & PUMP LG	433,327	40,259,658	2,670	162,295	0.0929
27	07APSA010S - IRG & PUMP SM	5,751	636,944	350	16,431	0.1108
28	07APSAL10X - IRG & PUMP - LG	186,470	17,614,213	1,481	125,908	0.0945
29	07APSAS10X - IRG & PUMP - SM	7,500	815,517	426	17,606	0.1087
30	07APSV006A-LRG POWER OPT	2,166	168,268	2	1,083,000	0.0777
31	07APSV023A-SM POWER OPT S	326	32,917	4	81,500	0.1010
32	07APSVCNLL-LG LOAD CANAL	21,526	1,792,800	47	458,000	0.0833
33	07APSVCNLS-SM LOAD CANAL	41	6,051	12	3,417	0.1476
34	07LNX00015-ANNUAL 80%GUAR		2,657			
35	07LNX00035-ADV 80%MO GUAR		477			
36	07LNX00040-ADV+REFCHG+80%		145,883			
37	07LNX00310 80% ANNUAL GTY		844			
38	07LNX00311 - LINE EXT 80% GTY		1,661			
39	07LNX00312 - ID LINE EXT		56,021			
40	07APSN010L - ID LG IRR & PUMP	4,265	402,654	32	133,281	0.0944
41	TOTAL Billed	54,127,172	4,894,019,840	1,840,754	29,405	0.0904
42	Total Unbilled Rev.(See Instr. 6)	190,765	30,521,000	0	0	0.1600
43	TOTAL	54,317,937	4,924,540,840	1,840,754	29,509	0.0907

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	07APSN010S - IRRIGATION SM	179	18,874	6	29,833	0.1054
2	07APSNS10X - IRRIGATION SM	266	31,594	18	14,778	0.1188
3	REVENUE_ACCT ADJ		-262,486			
4	DSM REVENUE-IRRIGATION		1,665,919			
5	BLUE SKY REV-IRRIGATION		123	5		
6	UNBILLED REVENUE	-23	-2,000			0.0870
7						
8	OREGON					
9	01APSV0041-AG PMP SRVC		1,706,166	2,968		
10	01APSV0215-OR IRR TOU PILO		22,285	10		
11	01APSV041L-PUMP SERV >30KW		2,774,582	818		
12	01APSV041T - AGR PUMP SRV		30,659	61		
13	01APSV041X-AG PMP SRVC		983,513	1,963		
14	01APSV41XL-OR Pumping Serv		1,548,429	361		
15	01COST0041 -01APSV0041	139,150	8,197,344			0.0589
16	01COST0048 - 01LGSV0048	116,822	5,807,445			0.0497
17	01COST0215-OR TOU PILOT COST	6,180	253,399			0.0410
18	01COSTS028 G SERV CST > 30	506	30,399			0.0601
19	01CSTUSB41-USBR IRR CONTRA	74,976	4,414,496			0.0589
20	01GNSB0028-OR GENL SVC > 30		3,574			
21	01GNSV0028, OR GEN SRV > 30		15,292	2		
22	01HABIT041 - 01APSV0041 AG	11	657			0.0597
23	01LGSB0048 - LG GEN SVC > 1000		1,113,335	3		
24	01LGSV0048-1000KW AND OVR		1,477,572	3		
25	01LNX00103-LINE EXT 80% G		41,190			
26	01LNX00109-REF/NREF ADV +		303			
27	01LNX00110-REF/NREF ADV +		189,657			
28	01LNX00310-LINE EXTENSION		17,246			
29	01PTOU0041 - 01APSV0041 AG	578	33,823			0.0585
30	01RENEW041 - 01APSV0041 AG	145	8,522			0.0588
31	01STDAY041 - DAILY STD OFFER	136	7,462			0.0549
32	01USBR0215-OR IRG TOU PILOT		232,057	84		
33	01USBRGV41-IRG TOU W/O BPA		72,811	9		
34	01USBROF41-KLAMATH BASIN		1,402,306	484		
35	01USBRON41-KLAMATH BASIN		1,956,320	1,164		
36	01VIR41136-OR VOLUME INC		60,774	24		
37	01VRU41136-VOL INC USB		344,323	95		
38	01VRU41215-VOL INC USB TOU		54,000	7		
39	01LNX00312 - OR IRG LINE EXT		35,861			
40	01NMT41135 - NETMTR AG PMP		12,483	14		
41	TOTAL Billed	54,127,172	4,894,019,840	1,840,754	29,405	0.0904
42	Total Unbilled Rev.(See Instr. 6)	190,765	30,521,000	0	0	0.1600
43	TOTAL	54,317,937	4,924,540,840	1,840,754	29,509	0.0907

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/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	01NMT41215-NET MTR APSV TOU		1			
2	01NMU41135 -NET MTR <PRJ		27,245	7		
3	REVENUE_ACCT ADJ		-50,685			
4	DSM REVENUE-IRRIGATION		629,597			
5	BLUE SKY REV-IRRIGATION		353			
6	SOLAR FEED-IN REVENUE		35,884			
7	UNBILLED REVENUE	3,306	481,000			0.1455
8						
9	UTAH					
10	08APSV0010-IRR & SOIL DRA	203,511	15,809,475	2,913	69,863	0.0777
11	08APSV10NS- LG SOIL DRAIN	36,429	2,601,090	239	152,423	0.0714
12	08LNX00004-ANNUAL 80%GUAR		5,619			
13	08LNX00014-80% MIN MNTHLY		11,574			
14	08LNX00017-ADV/REF&80%ANN		193,562			
15	08LNX00310 - IRR, 80% ANN MIN		19,656			
16	08LNX00311 - LINE EXT 80% GTY		368			
17	08LNX00312 UT IRG LINE EXT		25,487			
18	08NMT10135-UT IRR_SOIL DRNG	7,109	543,401	36	197,472	0.0764
19	REVENUE_ACCT ADJ		-115,100			
20	DSM REVENUE-IRRIGATION		729,302			
21	SOLAR FEED-IN REVENUE		38,170			
22	UNBILLED REVENUE	-197	-12,000			0.0609
23						
24	WASHINGTON					
25	02APSV0040-WA AG PMP SRVC	117,096	10,224,628	3,177	36,857	0.0873
26	02APSV040X-WA AG PMP SRVC	51,703	4,594,621	1,989	25,994	0.0889
27	02LNX00103-LINE EXT 80% G		9,308			
28	02LNX00105-CNTRCT $ MIN G		76			
29	02LNX00109-REF/NREF ADV +		9,250			
30	02LNX00110-REF/NREF ADV +		178,594			
31	02LNX00310 - IRG 80% ANN MIN		12,468			
32	02LNX00311 - LINE EXT 80%		170			
33	02LNX00312 - WA IRG LINE EXT		39,308			
34	02NMT40135-WA NET MTR -IRG	154	14,855	6	25,667	0.0965
35	REVENUE ADJ - DEF NPC		99,305			
36	REVENUE_ACCT ADJ		-619,160			
37	DSM REVENUE-IRRIGATION		518,251			
38	BLUE SKY REV-IRRIGATION		229	6		
39	UNBILLED REVENUE	1,863	830,000			0.4455
40						
41	TOTAL Billed	54,127,172	4,894,019,840	1,840,754	29,405	0.0904
42	Total Unbilled Rev.(See Instr. 6)	190,765	30,521,000	0	0	0.1600
43	TOTAL	54,317,937	4,924,540,840	1,840,754	29,509	0.0907

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/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	WYOMING					
2	05APS00040-AG PUMPING SVC	20,534	1,713,878	689	29,803	0.0835
3	05APSNS040-AG PUMPING SVC -	1,124	92,262	19	59,158	0.0821
4	05LNX00103-LINE EXT 80% G		5,589			
5	05LNX00109-REF/NREF ADV +		1,019			
6	05LNX00110-REF/NREF ADV +		45,944			
7	05LNX00310-LINE EXTCONTRAC		205			
8	05LNX00312 - WY IRG LINE EXT		11,016			
9	REVENUE_ACCT ADJ		579			
10	DSM REVENUE-IRRIGATION		19,873			
11	UNBILLED REVENUE	-7	-1,000			0.1429
12	05APS00040-AG PUMPING SVC	126	9,430	1	126,000	0.0748
13	05LNX00110-REF/NREF ADV +		13,106			
14	05LNX00310-LINE EXTENSION		1,218			
15	05LNX00312 - WY IRG LINE EXT		1,031			
16	09APSNS210-IRR & SOIL DRA -	372	35,824	2	186,000	0.0963
17	09APSV0210-IRR & SOIL DRA	4,722	407,745	91	51,890	0.0864
18	DSM REVENUE-IRRIGATION		4,979			
19						
20	LESS MULTIPLE BILLINGS			-833		
21						
22	TOTAL IRRIGATION SALES	1,539,322	149,350,706	23,487	65,539	0.0970
23						
24	PUBLIC STREET & HWY LIGHTING					
25	CALIFORNIA					
26	06CUSL053E-SPECIAL CUST O	1,205	214,415	106	11,368	0.1779
27	06CUSL058F-CUST OWND STR	80	16,119	20	4,000	0.2015
28	06HPSV0051-HI PRESSURE SO	604	204,084	78	7,744	0.3379
29	06OALT015N-OUTD AR LGT SR	1	143	1	1,000	0.1430
30	REVENUE_ACCT ADJ		-10,806			
31	DSM REVENUE-PUB ST & HWY LT		14,137			
32	SOLAR FEED-IN REVENUE		1,582			
33	UNBILLED REVENUE	199	43,000			0.2161
34						
35	IDAHO					
36	07GNSV023S-IDAHO TRAFFIC	140	17,716	25	5,600	0.1265
37	07SLCO0011-STR LGT CO-OWN	114	53,464	52	2,192	0.4690
38	07SLCU012E-ENGY STR LGT	364	41,088	31	11,742	0.1129
39	07SLCU012F-FULL MNT STR	1,873	377,841	190	9,858	0.2017
40	07SLCU012P-PART MNT STR LGT	194	28,602	16	12,125	0.1474
41	TOTAL Billed	54,127,172	4,894,019,840	1,840,754	29,405	0.0904
42	Total Unbilled Rev.(See Instr. 6)	190,765	30,521,000	0	0	0.1600
43	TOTAL	54,317,937	4,924,540,840	1,840,754	29,509	0.0907

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 2016/Q4

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1	REVENUE_ACCT ADJ		-3,684			
2	DSM REVENUE-PUB ST & HWY LT		13,100			
3	UNBILLED REVENUE	-22	-4,000			0.1818
4						
5	OREGON					
6	01COSL0052-STR LGT SRVC C	394	59,504	35	11,257	0.1510
7	01CUSL0053-CUS-OWNED MTRD	658	49,158	72	9,139	0.0747
8	01CUSL053E-STR LGT SVC	8,690	649,284	192	45,260	0.0747
9	01CUSL053F-STR LGT SRVC C	121	11,596	9	13,444	0.0958
10	01HPSV0051-HI PRESSURE SO	19,083	4,045,780	747	25,546	0.2120
11	01LEDSL051-OR LED PILOT	327	114,116	52	6,288	0.3490
12	01MVSL0050-MERC VAPSTR LG	7,527	1,002,381	233	32,305	0.1332
13	01OALT015N-OUTD AR LGT NR	13	2,285	6	2,167	0.1758
14	01OALTB15N-OR OUTD AR LGT	3	497	2	1,500	0.1657
15	REVENUE_ACCT ADJ		-11,107			
16	DSM REVENUE-PUB ST & HWY LT		144,453			
17	SOLAR FEED-IN REVENUE		8,752			
18	UNBILLED REVENUE	752	125,000			0.1662
19						
20	UTAH					
21	08CFR00012-STR LGTS (CONV		54			
22	08CFR00051-MTH FAC SRVCHG		4,529			
23	08CFR00062-STREET LIGHTS		79			
24	08OALT007N-SECURITY AR LG	7	-4,041	6	1,167	-0.5773
25	08TOSS015F-TRAFFIC SIG NM	1,151	105,692	121	9,512	0.0918
26	08SLCO0011-STR LGT CO-OWN	14,910	4,564,063	753	19,801	0.3061
27	08TOSS0015-TRAF & OTHER S	2,955	348,381	1,519	1,945	0.1179
28	08MONL0015-MTR OUTDONIGHT	861	68,753	76	11,329	0.0799
29	08SLCU012P-STR LGT CUST-O	4,725	604,850	193	24,482	0.1280
30	08SLCU012F-STR LGT CUST-O	1,170	164,607	79	14,810	0.1407
31	08SLCU012E-DECOR CUST-OWN	50,408	3,309,347	784	64,296	0.0657
32	REVENUE_ACCT ADJ		-89,599			
33	DSM REVENUE-PUB ST & HWY LT		340,659			
34	SOLAR FEED-IN REVENUE		37,675			
35	UNBILLED REVENUE	714	90,000			0.1261
36						
37	WASHINGTON					
38	02CFR00012-STR LGTS (CONV		91			
39	02COSL0052-WA STR LGT SRV	159	31,834	14	11,357	0.2002
40	02CUSL053F-WA STR LGT SRV	3,440	251,209	112	30,714	0.0730
41	TOTAL Billed	54,127,172	4,894,019,840	1,840,754	29,405	0.0904
42	Total Unbilled Rev.(See Instr. 6)	190,765	30,521,000	0	0	0.1600
43	TOTAL	54,317,937	4,924,540,840	1,840,754	29,509	0.0907

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1	02CUSL053M-WA STR LGT SRV	1,077	77,923	105	10,257	0.0724
2	02SLCO0051-WA COMPANY	3,843	772,543	186	20,661	0.2010
3	02MVSL0057-WA MERC VAPSTR	1,676	214,634	40	41,900	0.1281
4	REVENUE ADJ - DEF NPC		6,173			
5	REVENUE_ACCT ADJ		-41,006			
6	DSM REVENUE-PUB ST & HWY LT		29,134			
7	UNBILLED REVENUE	-166	-17,000			0.1024
8						
9	WYOMING					
10	05COSL0057-CO-OWND STR LG	254	48,848	17	14,941	0.1923
11	05CUSL0058-CUST OWND STR	76	4,466	11	6,909	0.0588
12	05CUSL0E58-CUST OWNED STR	1,069	63,025	31	34,484	0.0590
13	05CUSL0M58-CUST OWNED STR	44	3,145	3	14,667	0.0715
14	05HPSV0051-HI PRESSURE SO	5,292	1,023,371	185	28,605	0.1934
15	05MVS00053-MERCURY VAPOR	3,561	422,684	240	14,838	0.1187
16	05OALT015N-OUTD AR LGT SR	30	3,381	2	15,000	0.1127
17	REVENUE_ACCT ADJ		-2,179			
18	DSM REVENUE-PUB ST & HWY LT		17,299			
19	UNBILLED REVENUE	232	35,000			0.1509
20	09MONL0213-WY MTR OUTDOOR	25	2,585	1	25,000	0.1034
21	09SLCO0211-STR LGT CO-OWN	1,491	340,316	49	30,429	0.2282
22	09SLCUP212-CUST OWNED	34	5,043	5	6,800	0.1483
23	09TOSS0213-TRAFFIC & OTHER	37	1,976	14	2,643	0.0534
24	DSM REVENUE-PUB ST & HWY LT		3,862			
25	UNBILLED REVENUE	96	17,000			0.1771
26						
27	LESS MULTIPLE BILLINGS			-2,943		
28						
29	TOTAL PUBLIC STREET & HWY LT	141,491	20,068,906	3,470	40,776	0.1418
30						
31	OTHER SALES TO PUBLIC AUTH					
32	UTAH					
33	08GNSV009M-MANL HIGH VOLT	250,041	14,735,630	1	250,041,000	0.0589
34	08PRSV031M-BKUP MNT&SUPPL	102,842	7,390,785	1	102,842,000	0.0719
35	REVENUE_ACCT ADJ		-169,167			
36	DSM REVENUE-OSPA		862,515			
37	SOLAR FEED-IN REVENUE		54,529			
38	UNBILLED REVENUE	-15,668	-889,000			0.0567
39						
40	TOTAL OTHER SALES TO PUBLIC	337,215	21,985,292	2	168,607,500	0.0652
41	TOTAL Billed	54,127,172	4,894,019,840	1,840,754	29,405	0.0904
42	Total Unbilled Rev.(See Instr. 6)	190,765	30,521,000	0	0	0.1600
43	TOTAL	54,317,937	4,924,540,840	1,840,754	29,509	0.0907

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1	FORFEITED DISCOUNTS					
2	CALIFORNIA					
3	06LPAY0300-RES-LATEFEE		194,256			
4	06LPAY0300-COM-LATEFEE		49,823			
5	06LPAY0300-IND-LATEFEE		59,652			
6	06LPAY0300-OTHER-LATEFEE		-1,666			
7						
8	IDAHO					
9	07LPAY0300-RES-LATEFEE		222,191			
10	07LPAY0300-COM-LATEFEE		39,149			
11	07LPAY0300-IND-LATEFEE		214,798			
12	07LPAY0300-OTHER-LATEFEE		642			
13						
14	OREGON					
15	01LPAY0300-RES-LATEFEE		2,897,375			
16	01LPAY0300-COM-LATEFEE		611,051			
17	01LPAY0300-IND-LATEFEE		200,621			
18	01LPAY0300-OTHER-LATEFEE		3,886			
19						
20	UTAH					
21	08LPAY0300-RES-LATEFEE		2,525,640			
22	08LPAY0300-COM-LATEFEE		597,985			
23	08LPAY0300-IND-LATEFEE		400,992			
24	08LPAY0300-OTHER-LATEFEE		61,323			
25	OTHER		1,574			
26						
27	WASHINGTON					
28	02LPAY0300-RES-LATEFEE		532,842			
29	02LPAY0300-COM-LATEFEE		111,313			
30	02LPAY0300-IND-LATEFEE		27,753			
31	02LPAY0300-OTHER-LATEFEE		-12,875			
32						
33	WYOMING					
34	05LPAY0300-RES-LATEFEE		409,905			
35	05LPAY0300-COM-LATEFEE		98,665			
36	05LPAY0300-IND-LATEFEE		46,995			
37	05LPAY0300-OTHER-LATEFEE		2,974			
38	05LPAY0300-RES-LATEFEE		49,650			
39	05LPAY0300-COM-LATEFEE		10,952			
40	05LPAY0300-IND-LATEFEE		13,296			
41	TOTAL Billed	54,127,172	4,894,019,840	1,840,754	29,405	0.0904
42	Total Unbilled Rev.(See Instr. 6)	190,765	30,521,000	0	0	0.1600
43	TOTAL	54,317,937	4,924,540,840	1,840,754	29,509	0.0907

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 2016/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.
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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	05LPAY0300-OTHER-LATEFEE		1,007			
2	TOTAL FORFEITED DISCOUNTS		9,371,769			
3						
4	MISCELLANEOUS SERVICE REV					
5	CALIFORNIA					
6	06CFR00003-MTH MAINTENANC		1,454			
7	06CONN0300-CA RECONNECTIO		24,750			
8	06FCBUYOUT		24,993			
9	06RCHK0300-CA RET CHK CHR		10,680			
10	06TAMP0300-CA TAMP & UNAU		975			
11	06TEMP0300-CA TEMP SRVC C		3,575			
12	06TRBL0300-CA TROUBLE CAL		30			
13	06XMTRTAMP-TMPRING - UNAU		293			
14	HOME COMFORT		18			
15						
16	IDAHO					
17	07CFR00001-MTH FAC SRVCHG		1,682			
18	07CONN0300-ID RECONNECTIO		14,090			
19	07FCBUYOUT - FAC CHG BUYOUT		76,961			
20	07RCHK0300-ID RET CHK CHR		28,600			
21	07TAMP0300		150			
22	07TEMP0014-TEMP SRVC CONN		29,725			
23	OTHER		1,230			
24						
25	OREGON					
26	01CFR00001-MTH FACILITY S		91,338			
27	01CFR00003-MTH MAINTENANC		25,986			
28	01CFR00004-MTH MAINTENANC		25,929			
29	01CFR00005-INTERMTNT SRVC		37,101			
30	01CFR00013-MTH MISC CHRG		53,234			
31	01CFR00014-YR MISC CHRG		-5			
32	01CONN0300-RECONNECTION C		268,765			
33	01CONTSERV-OR 3RD PARTY		9,087			
34	01ESSC0600 - ESS CHARGES		3,096			
35	01FCBUYOUT-FAC CHG BUYOUT		277,357			
36	01RCHK0300-RETURNED CHECK		266,880			
37	01TAMP0300-TAMP & UNAUTH		16,575			
38	01TEMP0300-TEMP SRVC CHRG		173,425			
39	01XMTRTAMP-TAMPRING - UNAU		5,532			
40	OTHER		-73,248			
41	TOTAL Billed	54,127,172	4,894,019,840	1,840,754	29,405	0.0904
42	Total Unbilled Rev.(See Instr. 6)	190,765	30,521,000	0	0	0.1600
43	TOTAL	54,317,937	4,924,540,840	1,840,754	29,509	0.0907

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 2016/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	UTAH					
2	08CFR00013-MTH MISC CHRG		135,561			
3	08CFR00051-MTH FAC SRVCHG		86,174			
4	08CFR00052-ANN FAC SVCCHG		424			
5	08CFR00053-MTHLY MAINTFEE		12,007			
6	08CFR00054-NRES EMERGENCY		4,976			
7	08CFR00063-MTH MISC CHARG		2,358			
8	08CFR00064-ANN MISC CHARG		6,660			
9	08CONN0300-RECONN&DISCONN		296,340			
10	08CONTSERV-3RD PARTY O/S		91,620			
11	08FCBUYOUT-FAC CHG BUYOUT		298,008			
12	08INFO0300-CUST/3RD P REQ		80			
13	08NCON0300-UT FEE NRES RE		3,830			
14	08NSMTR300-NON STAN MTR		849			
15	08PRINT300-SCREEN PRINT FOR		226			
16	08RCHK0300-UT RET CHK CHR		439,620			
17	08RCON0001-CONNECT FEE		1,751,511			
18	08RESD0001-RES SRVC		3,695			
19	08TAMP0300-TAMPERING&UNAU		8,025			
20	08TEMP0014-TEMP SRVC CONN		627,450			
21	08XMTRTAMP-TMPRING - UNAU		1,865			
22	ENERGY FINANSWER NEW COM		2,644			
23	08VISIT300 - UT VISIT, SERVICE		44,390			
24	OTHER		-48,773			
25						
26	WASHINGTON					
27	02CFR00003-MTH MAINTENANC		1,320			
28	02CFR00004-EMRGNCY ST&BY		5,892			
29	02CFR00005-INTERMTNT SRVC		4,147			
30	02CONN0300-WA RECONNECTIO		53,525			
31	02FCBUYOUT - FAC CHG BUYOUT		53,067			
32	02RCHK0300-WA RET CHK CHR		49,940			
33	02TAMP0300-WA TAMP & UNAU		2,775			
34	02TEMP0300-WA TEMP SRVC C		20,430			
35	02XMTRTAMP-TMPRING - UNAU		655			
36	02XTHEFREV-THEFT OF		-5,809			
37	HOME COMFORT		27			
38	OTHER		-3,056			
39						
40						
41	TOTAL Billed	54,127,172	4,894,019,840	1,840,754	29,405	0.0904
42	Total Unbilled Rev.(See Instr. 6)	190,765	30,521,000	0	0	0.1600
43	TOTAL	54,317,937	4,924,540,840	1,840,754	29,509	0.0907

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SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	WYOMING					
2	05CFR00003-MTH MAINTENANC		1,768			
3	05CFR00004-EMRGNCY ST&BY		18,474			
4	05CFR00005-INTERMTNT SRVC		10,063			
5	05CFR00013-MTH MISC CHRG		3,186			
6	05CONN0300-WY RECONNECTIO		74,688			
7	05FCBUYOUT - FAC CHG BUYOUT		34,574			
8	05NSMTR300-NON STANDARD		370			
9	05RCHK0300-WY RET CHK CHR		82,320			
10	05RESD0002-WY RES SRVC		825			
11	05TAMP0300		900			
12	05TEMP0300-WY TEMP SRVC C		47,600			
13	05XMTRTAMP-TMPRING - UNAU		183			
14	09CFR00005-INTERMTNT SRVC		339			
15	OTHER		-5,804			
16	05CONN0300-WY RECONNECTIO		8,710			
17	05RCHK0300-WY RET CHK CHR		7,260			
18	05SERV0300-WY SRVC CALLS		120			
19	05TAMP0300		75			
20	05TEMP0300-WY TEMP SRVC C		510			
21	05XMTRTAMP-TAMPERING -		17			
22	09CFR00001-MTH FAC SRVCHG		4,726			
23	09CFR00014-YR MISC CHRG		3			
24						
25	TOTAL MISC SERVICE REV		5,643,618			
26						
27	SALES OF WATER & WATER PWR					
28	IDAHO					
29	WATER & WATER PWR SALES		3,452			
30						
31	UTAH					
32	WATER & WATER PWR SALES		71,581			
33						
34	TOTAL SALES OF WATER & WTR		75,033			
35						
36	RENT FROM ELEC PROPERTIES					
37	CALIFORNIA					
38	06CFR00006-MTH RNTAL CHRG		1,710			
39	RENT REVENUE-HYDRO		1,450			
40	RENT REVENUE-SUBLEASES		19,200			
41	TOTAL Billed	54,127,172	4,894,019,840	1,840,754	29,405	0.0904
42	Total Unbilled Rev.(See Instr. 6)	190,765	30,521,000	0	0	0.1600
43	TOTAL	54,317,937	4,924,540,840	1,840,754	29,509	0.0907

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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	JOINT USE		517,335			
2						
3	IDAHO					
4	07CFR00009-YR LSE CHRG-EQ		723			
5	07INVCHG00-INVEST MNT CHG		150			
6	07POLE0075-STEEL POLES US		274			
7	RENT REVENUE-HYDRO		73,480			
8	RENT REVENUE-TRANSMISSION		9,780			
9	RENT REVENUE-DISTRIBUTION		550			
10	RENT REVENUE-SUBLEASES		2,216			
11	JOINT USE		161,597			
12						
13	OREGON					
14	01CFR00006-MTH RNTAL CHRG		834,918			
15	RENTS - COMMON		676,677			
16	RENTS - NON COMMON		25			
17	MCI FOGWIRE REVENUE		3,343,623			
18	RENT REVENUE-SUBLEASES		45,050			
19	RENT REVENUE-HYDRO		30,404			
20	RENT REVENUE-TRANSMISSION		274,779			
21	RENT REVENUE-DISTRIBUTION		61,763			
22	RENT REVENUE-GENERAL		61,466			
23	JOINT USE		2,778,597			
24						
25	UTAH					
26	08CFR00056-MTH EQUIP RENT		33			
27	08CFR00058-MTH EQUIP LEAS		487,051			
28	08INVCHG0N-INVEST MNT CHG		4,392			
29	08INVCHG0R-INVEST MNT CHG		230			
30	08POLE0075-STEEL POLES US		54,247			
31	RENTS - NON COMMON		11,903			
32	RENT REVENUE-STEAM		104,460			
33	RENT REVENUE-HYDRO		167,557			
34	RENT REVENUE-TRANSMISSION		1,144,793			
35	RENT REVENUE-DISTRIBUTION		655,071			
36	RENT REVENUE-GENERAL		23,179			
37	RENT REVENUE-SUBLEASES		2,692,996			
38	JOINT USE		4,341,955			
39						
40						
41	TOTAL Billed	54,127,172	4,894,019,840	1,840,754	29,405	0.0904
42	Total Unbilled Rev.(See Instr. 6)	190,765	30,521,000	0	0	0.1600
43	TOTAL	54,317,937	4,924,540,840	1,840,754	29,509	0.0907

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1	WASHINGTON					
2	02CFR00001-MTH FACILITY S		2,104			
3	02CFR00006-MTH RNTAL CHRG		9,073			
4	RENT REVENUE-HYDRO		355,923			
5	RENT REVENUE-TRANSMISSION		19,600			
6	RENT REVENUE-DISTRIBUTION		19,662			
7	RENT REVENUE-GENERAL		42,719			
8	JOINT USE		817,250			
9						
10	WYOMING					
11	05CFR00001-MTH FACILITY S		11,524			
12	05CFR00006-MTH RNTAL CHRG		2,482			
13	RENT REVENUE-STEAM		115,420			
14	RENT REVENUE-HYDRO		24,974			
15	RENT REVENUE-TRANSMISSION		17,506			
16	RENT REVENUE-DISTRIBUTION		150			
17	RENT REVENUE-GENERAL		59,793			
18	RENT REVENUE-SUBLEASES		31,079			
19	JOINT USE		334,646			
20	09POLE0075-STEEL POLES US		18,313			
21	RENT REVENUE-STEAM		28,336			
22						
23	TOTAL RENT FROM ELEC PROP		20,494,188			
24						
25	OTHER ELECTRIC REVENUE					
26	WIND BASED ANCILLARY SVC		10,840,910			
27	FERC TRANSMISSION REFUND		-7,093,960			
28	OTH ELEC ESTIMATE		-792,052			
29	RENEWABLE ENERGY CREDITS		-7,116,003			
30	NON-WHEELING SYSTEM		6,159,270			
31	OTHER ELEC (EXCLUDE WHEELIN		27,790			
32						
33	CALIFORNIA					
34	CA GHG ALLOW REV AMORT		11,196,617			
35	3RD PARTY TRANS O&M		60,564			
36	FISH, WILDLIFE, RECR		7,820			
37	OTHER ELEC (EXCLUDE WHEELIN		-215			
38						
39						
40						
41	TOTAL Billed	54,127,172	4,894,019,840	1,840,754	29,405	0.0904
42	Total Unbilled Rev.(See Instr. 6)	190,765	30,521,000	0	0	0.1600
43	TOTAL	54,317,937	4,924,540,840	1,840,754	29,509	0.0907

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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	IDAHO					
2	3RD PARTY TRANS O&M		-11,099			
3	OTHER ELEC (EXCLUDE WHEELIN		-5			
4	OREGON					
5	EIM REVENUE - FORECASTING		25,900			
6	3RD PARTY TRANS O&M		183,519			
7	OTHER ELEC (EXCLUDE WHEELIN		1,707,652			
8						
9	UTAH					
10	ELEC INC-OTHR		48,096			
11	FLYASH SALES		1,789,010			
12	3RD PARTY TRANS O&M		208,255			
13	FISH, WILDLIFE, RECR		2,720			
14	OTHER ELEC (EXCLUDE WHEELIN		-42			
15	M&S INVENTORY REVENUE		1,450,819			
16						
17	WASHINGTON					
18	TIMBER SALES - UTILITY PROP		727,541			
19	FISH, WILDLIFE, RECR		9,390			
20	OTHER ELEC (EXCLUDE WHEELIN		-3			
21	WASH COLSTRIP 3		-52,188			
22						
23	WYOMING					
24	ELEC INC-OTHR		5			
25	FLYASH SALES		2,534,354			
26	WY REG RECOVERY FEE		351,447			
27	3RD PARTY TRANS O&M		83,503			
28	OTHER ELEC (EXCLUDE WHEELIN		17			
29						
30	TOTAL OTHER ELEC REV		22,349,632			
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	54,127,172	4,894,019,840	1,840,754	29,405	0.0904
42	Total Unbilled Rev.(See Instr. 6)	190,765	30,521,000	0	0	0.1600
43	TOTAL	54,317,937	4,924,540,840	1,840,754	29,509	0.0907

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SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
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	Actual Demand (MW) Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Requirement Sales:					
2	Helper City	RQ	T-6	1	1	1
3	Helper City Annex	RQ	T-6	1	1	1
4	Navajo Tribal Utility Authority	RQ	T-12	3	3	2
5	Navajo Tribal Util. Auth. (Mexican Hat)	RQ	T-6	0	0	0
6	Navajo Tribal Util. Auth. (Red Mesa)	RQ	T-6	1	1	1
7	Portland General Electric Company	RQ	147	NA	NA	NA
8	Accrual	RQ	NA	NA	NA	NA
9						
10	Nonrequirement Sales:					
11	Arizona Electric Power Cooperative	SF	T-12	NA	NA	NA
12	Arizona Public Service Company	SF	T-12	NA	NA	NA
13	Avangrid Renewables, LLC	AD	T-12	NA	NA	NA
14	Avangrid Renewables, LLC	SF	T-12	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/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
5,652	104,277	99,944		204,221	2
3,593	68,423	63,519		131,942	3
1,267	26,882	40,736		67,618	4
919	16,628	16,005		32,633	5
8,781	134,141	152,975		287,116	6
6,558		687,015		687,015	7
-1,220			-38,087	-38,087	8
					9
					10
218,559		4,251,239		4,251,239	11
145,346		4,009,759		4,009,759	12
			38	38	13
841,613		20,711,878		20,711,878	14
25,550	350,351	1,060,194	-38,087	1,372,458	
6,615,415	11,925,385	302,922,334	-139,121,717	175,726,002	
6,640,965	**12,275,736**	**303,982,528**	**-139,159,804**	**177,098,460**	

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 2016/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	Avista Corporation	SF	T-12	NA	NA	NA
2	Avista Corporation	SF	T-13	NA	NA	NA
3	BP Energy Company	SF	T-12	NA	NA	NA
4	Basin Electric Power Cooperative	SF	T-12	NA	NA	NA
5	Black Hills Power, Inc.	AD	441	NA	NA	NA
6	Black Hills Power, Inc.	AD	T-12	NA	NA	NA
7	Black Hills Power, Inc.	LF	441	50	50	38
8	Black Hills Power, Inc.	SF	T-12	NA	NA	NA
9	Bonneville Power Administration	AD	T-12	NA	NA	NA
10	Bonneville Power Administration	LU	519	NA	NA	NA
11	Bonneville Power Administration	SF	T-12	NA	NA	NA
12	Bonneville Power Administration	SF	T-13	NA	NA	NA
13	British Columbia Hydro and Power	SF	T-13	NA	NA	NA
14	Brookfield Energy Marketing L.P.	SF	T-12	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.
67,250		1,249,538		1,249,538	1
17			432	432	2
534,363		13,195,990		13,195,990	3
22,571		488,246		488,246	4
2			41	41	5
51			247	247	6
252,506	7,529,185	5,034,260		12,563,445	7
127,044		2,752,197		2,752,197	8
			309,498	309,498	9
41,513		2,894,286		2,894,286	10
71,327		1,473,632		1,473,632	11
422			9,954	9,954	12
1			18	18	13
33,404		755,168		755,168	14
25,550	350,351	1,060,194	-38,087	1,372,458	
6,615,415	11,925,385	302,922,334	-139,121,717	175,726,002	
6,640,965	**12,275,736**	**303,982,528**	**-139,159,804**	**177,098,460**	

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 2016/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	California Independent System Operator	AD	T-12	NA	NA	NA
2	California Independent System Operator	SF	T-12	NA	NA	NA
3	Calpine Energy Services, L.P.	SF	T-12	NA	NA	NA
4	Cargill Power Markets, LLC	AD	T-12	NA	NA	NA
5	Cargill Power Markets, LLC	SF	T-12	NA	NA	NA
6	City of Anaheim	SF	T-12	NA	NA	NA
7	City of Burbank	SF	T-12	NA	NA	NA
8	City of Glendale	SF	T-12	NA	NA	NA
9	City of Hurricane	LF	T-12	NA	NA	NA
10	City of Redding	SF	T-12	NA	NA	NA
11	City of Roseville	SF	T-12	NA	NA	NA
12	Clatskanie People's Utility District	SF	T-12	NA	NA	NA
13	ConocoPhillips Company	SF	T-12	NA	NA	NA
14	EDF Trading North America, LLC	SF	T-12	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2016/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.
-8,140			-349,648	-349,648	1
19,655		634,722		634,722	2
7,602		86,590		86,590	3
			61	61	4
675,699		18,675,156		18,675,156	5
90,000		1,589,733		1,589,733	6
45,525		1,045,497		1,045,497	7
600		15,900		15,900	8
246		15,990		15,990	9
44,241		914,722		914,722	10
25,768		708,939		708,939	11
4,970		93,077		93,077	12
2,588		32,094		32,094	13
1,167,035		28,638,423		28,638,423	14
25,550	350,351	1,060,194	-38,087	1,372,458	
6,615,415	11,925,385	302,922,334	-139,121,717	175,726,002	
6,640,965	**12,275,736**	**303,982,528**	**-139,159,804**	**177,098,460**	

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 2016/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	El Paso Electric Company	SF	T-12	NA	NA	NA
2	Energy Keepers, Inc.	SF	T-12	NA	NA	NA
3	Eugene Water & Electric Board	SF	T-12	NA	NA	NA
4	Exelon Generation Company, LLC	AD	T-12	NA	NA	NA
5	Exelon Generation Company, LLC	SF	T-12	NA	NA	NA
6	Gridforce Energy Management	SF	T-13	NA	NA	NA
7	Guzman Renewables Energy Partners LLC	SF	T-12	NA	NA	NA
8	Idaho Power Company	SF	T-12	NA	NA	NA
9	Idaho Power Company	SF	T-13	NA	NA	NA
10	Idaho Power Company	SF	WSPP - Q	NA	NA	NA
11	Los Angeles Dept. of Water and Power	LU	301	NA	NA	NA
12	Los Angeles Dept. of Water and Power	SF	T-12	NA	NA	NA
13	Macquarie Energy LLC	SF	T-12	NA	NA	NA
14	Modesto Irrigation District	SF	T-12	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.
23,327		641,744		641,744	1
202		5,258		5,258	2
19,800		380,958		380,958	3
-25					4
1,719,620		41,338,964		41,338,964	5
85			2,233	2,233	6
93,114		2,650,832		2,650,832	7
12,631		210,000		210,000	8
357			8,084	8,084	9
44,451		1,297,772		1,297,772	10
122,424		3,318,535		3,318,535	11
142,040		3,375,428		3,375,428	12
98,862		2,204,148		2,204,148	13
8,553		214,509		214,509	14
25,550	350,351	1,060,194	-38,087	1,372,458	
6,615,415	11,925,385	302,922,334	-139,121,717	175,726,002	
6,640,965	**12,275,736**	**303,982,528**	**-139,159,804**	**177,098,460**	

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 2016/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	Morgan Stanley Capital Group Inc.	AD	T-12	NA	NA	NA
2	Morgan Stanley Capital Group Inc.	OS	T-12	NA	NA	NA
3	Morgan Stanley Capital Group Inc.	SF	T-12	NA	NA	NA
4	Municipal Energy Agency of Nebraska	AD	T-12	NA	NA	NA
5	Municipal Energy Agency of Nebraska	SF	T-12	NA	NA	NA
6	NaturEner Power Watch, LLC	SF	T-13	NA	NA	NA
7	Nevada Power Company	SF	WSPP - Q	NA	NA	NA
8	NextEra Energy Power Marketing, LLC	SF	T-12	NA	NA	NA
9	NorthWestern Corporation	OS	T-12	NA	NA	NA
10	NorthWestern Corporation	SF	T-12	NA	NA	NA
11	NorthWestern Corporation	SF	T-13	NA	NA	NA
12	NorthWestern Corporation	SF	WSPP - Q	NA	NA	NA
13	Portland General Electric Company	SF	T-12	NA	NA	NA
14	Portland General Electric Company	SF	T-13	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.
			181	181	1
			-6,720	-6,720	2
653,880		15,718,185		15,718,185	3
-40			-640	-640	4
19,789		415,094		415,094	5
16			271	271	6
23,113		499,056		499,056	7
2,800		56,900		56,900	8
			-3,772	-3,772	9
14,612		336,501		336,501	10
154			4,087	4,087	11
29,722		798,136		798,136	12
109,963		2,110,760	900	2,111,660	13
123			3,115	3,115	14
25,550	350,351	1,060,194	-38,087	1,372,458	
6,615,415	11,925,385	302,922,334	-139,121,717	175,726,002	
6,640,965	**12,275,736**	**303,982,528**	**-139,159,804**	**177,098,460**	

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 2016/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	Powerex Corporation	SF	T-12	NA	NA	NA
2	Public Service Company of Colorado	AD	T-12	NA	NA	NA
3	Public Service Company of Colorado	SF	T-12	NA	NA	NA
4	Public Service Company of New Mexico	SF	T-12	NA	NA	NA
5	PUD No. 1 of Chelan County	SF	T-13	NA	NA	NA
6	PUD No. 1 of Clark County	SF	T-12	NA	NA	NA
7	PUD No. 1 of Douglas County	SF	T-13	NA	NA	NA
8	PUD No. 1 of Snohomish County	SF	T-12	NA	NA	NA
9	Puget Sound Energy, Inc.	SF	T-12	NA	NA	NA
10	Puget Sound Energy, Inc.	SF	T-13	NA	NA	NA
11	Rainbow Energy Marketing Corporation	SF	T-12	NA	NA	NA
12	Rainbow Energy Marketing Corporation	SF	WSPP - Q	NA	NA	NA
13	Sacramento Municipal Utility District	SF	T-12	NA	NA	NA
14	Sacramento Municipal Utility District	SF	T-13	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.
123,216		2,031,813	1,550	2,033,363	1
-1			-24	-24	2
497,622		12,449,355		12,449,355	3
152,271		3,751,485		3,751,485	4
3			84	84	5
17,372		439,580		439,580	6
5			96	96	7
5,578		141,049		141,049	8
73,871		1,625,663	1,000	1,626,663	9
40			626	626	10
51,466		1,173,974		1,173,974	11
4,800		104,000		104,000	12
10,998		231,424		231,424	13
12			282	282	14
25,550	350,351	1,060,194	-38,087	1,372,458	
6,615,415	11,925,385	302,922,334	-139,121,717	175,726,002	
6,640,965	**12,275,736**	**303,982,528**	**-139,159,804**	**177,098,460**	

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 2016/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Salt River Project	AD	T-12	NA	NA	NA
2	Salt River Project	SF	T-12	NA	NA	NA
3	Seattle City Light	SF	T-12	NA	NA	NA
4	Seattle City Light	SF	T-13	NA	NA	NA
5	Sempra Generation, LLC	AD	T-12	NA	NA	NA
6	Sempra Generation, LLC	SF	T-12	NA	NA	NA
7	Shell Energy North America (US), L.P.	AD	T-12	NA	NA	NA
8	Shell Energy North America (US), L.P.	SF	T-12	NA	NA	NA
9	Sierra Pacific Power Company	SF	T-13	NA	NA	NA
10	Southern California Edison Company	SF	T-12	NA	NA	NA
11	Tacoma Power	SF	T-12	NA	NA	NA
12	Tacoma Power	SF	T-13	NA	NA	NA
13	Talen Energy Marketing, LLC	OS	T-12	NA	NA	NA
14	Talen Energy Marketing, LLC	SF	T-12	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.
-75			-1,556	-1,556	1
223,087		5,572,610		5,572,610	2
21,894		453,726		453,726	3
4			107	107	4
37			879	879	5
504,385		12,951,573		12,951,573	6
176			2,935	2,935	7
1,017,507		22,833,026		22,833,026	8
405			7,953	7,953	9
459,659		12,980,448		12,980,448	10
13,860		228,872		228,872	11
7			108	108	12
			-85	-85	13
21,496		476,486		476,486	14
25,550	350,351	1,060,194	-38,087	1,372,458	
6,615,415	11,925,385	302,922,334	-139,121,717	175,726,002	
6,640,965	**12,275,736**	**303,982,528**	**-139,159,804**	**177,098,460**	

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 2016/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	Tenaska Power Services Co.	SF	T-12	NA	NA	NA
2	Tenaska Power Services Co.	SF	WSPP - Q	NA	NA	NA
3	The Energy Authority, Inc.	SF	T-12	NA	NA	NA
4	TransAlta Energy Marketing (U.S.) Inc.	OS	T-12	NA	NA	NA
5	TransAlta Energy Marketing (U.S.) Inc.	AD	T-12	NA	NA	NA
6	TransAlta Energy Marketing (U.S.) Inc.	SF	T-12	NA	NA	NA
7	TransCanada Energy Sales Ltd.	SF	T-12	NA	NA	NA
8	Tri-State Gen. and Trans.	SF	T-12	NA	NA	NA
9	Tucson Electric Power Company	OS	T-12	NA	NA	NA
10	Tucson Electric Power Company	SF	T-12	NA	NA	NA
11	Turlock Irrigation District	SF	T-12	NA	NA	NA
12	UNS Electric, Inc.	SF	T-12	NA	NA	NA
13	Utah Associated Municipal Power Systems	OS	T-12	NA	NA	NA
14	Utah Associated Municipal Power Systems	SF	T-12	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/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.
265,090		5,647,281		5,647,281	1
1,497		38,092		38,092	2
34,949		761,626		761,626	3
			-283	-283	4
74			1,856	1,856	5
353,023		6,918,860		6,918,860	6
1,177		31,522		31,522	7
73,869		1,438,628		1,438,628	8
			-5,994	-5,994	9
212,477		5,014,074		5,014,074	10
164,101		4,498,268		4,498,268	11
55,608		1,358,298		1,358,298	12
			-338	-338	13
1,405		60,960		60,960	14
25,550	350,351	1,060,194	-38,087	1,372,458	
6,615,415	11,925,385	302,922,334	-139,121,717	175,726,002	
6,640,965	**12,275,736**	**303,982,528**	**-139,159,804**	**177,098,460**	

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	Utah Associated Municipal Power Systems	SF	WSPP - Q	NA	NA	NA
2	Utah Municipal Power Agency	LF	433	34	34	29
3	Utah Municipal Power Agency	SF	T-12	NA	NA	NA
4	Utah Municipal Power Agency	SF	WSPP - Q	NA	NA	NA
5	Vitol Inc.	SF	T-12	NA	NA	NA
6	Western Area Power Administration	SF	T-12	NA	NA	NA
7	Transmission Loss Sales Revenue	AD	T-11	NA	NA	NA
8	Transmission Loss Sales Revenue	OS	T-11	NA	NA	NA
9	Netting - Bookouts		NA	NA	NA	NA
10	Netting - Trading		NA	NA	NA	NA
11	Accrual		NA	NA	NA	NA
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.
		-6		-6	1
195,270	4,396,200	4,335,459		8,731,659	2
430		11,885		11,885	3
13,840		287,250		287,250	4
335,700		7,430,839		7,430,839	5
108,208		2,804,398		2,804,398	6
1,876			-1,334,659	-1,334,659	7
172,005			3,980,817	3,980,817	8
-6,130,887			-140,906,003	-140,906,003	9
			-657,255	-657,255	10
-15,343			-192,193	-192,193	11
					12
					13
					14
25,550	350,351	1,060,194	-38,087	1,372,458	
6,615,415	11,925,385	302,922,334	-139,121,717	175,726,002	
6,640,965	**12,275,736**	**303,982,528**	**-139,159,804**	**177,098,460**	

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

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 Line No.: 13 Column: b

Settlement adjustment.

Schedule Page: 310 Line No.: 13 Column: j

Settlement adjustment.

Schedule Page: 310.1 Line No.: 2 Column: j

Reserve share.

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

Settlement adjustment.

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

Settlement adjustment.

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

Settlement adjustment.

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

Settlement adjustment.

Schedule Page: 310.1 Line No.: 7 Column: b

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

Schedule Page: 310.1 Line No.: 9 Column: b

Settlement adjustment.

Schedule Page: 310.1 Line No.: 9 Column: j

Settlement adjustment.

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

Reserve share.

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

Reserve share.

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

Settlement adjustment.

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

Settlement adjustment.

Schedule Page: 310.2 Line No.: 4 Column: b

Settlement adjustment.

Schedule Page: 310.2 Line No.: 4 Column: j

Settlement adjustment.

Schedule Page: 310.2 Line No.: 9 Column: b

City of Hurricane - FERC T-12 - Contract termination date: August 31, 2017.

Schedule Page: 310.3 Line No.: 4 Column: b

Settlement adjustment.

Schedule Page: 310.3 Line No.: 6 Column: j

Reserve share.

Schedule Page: 310.3 Line No.: 9 Column: j

Reserve share.

Schedule Page: 310.3 Line No.: 11 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: 310.4 Line No.: 1 Column: b

Settlement adjustment.

Schedule Page: 310.4 Line No.: 1 Column: j

Settlement adjustment.

Schedule Page: 310.4 Line No.: 2 Column: b

Pursuant to FERC Docket No. ER10-2475-006,*et* al. revoking PacifiCorp's market-based rate authority.

Schedule Page: 310.4 Line No.: 2 Column: j

Pursuant to FERC Docket No. ER10-2475-006,*et* al. revoking PacifiCorp's market-based rate authority.

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.: 6 Column: j

Reserve share.

Schedule Page: 310.4 Line No.: 7 Column: a

This footnote applies to all occurrences of "Nevada Power Company" on pages 310-311. 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: 310.4 Line No.: 9 Column: b

Pursuant to FERC Docket No. ER10-2475-006,*et* al. revoking PacifiCorp's market-based rate authority.

Schedule Page: 310.4 Line No.: 9 Column: j

Pursuant to FERC Docket No. ER10-2475-006,*et* al. revoking PacifiCorp's market-based rate authority.

Schedule Page: 310.4 Line No.: 11 Column: j

Reserve share.

Schedule Page: 310.4 Line No.: 13 Column: j

Pond sales.

Schedule Page: 310.4 Line No.: 14 Column: j

Reserve share.

Schedule Page: 310.5 Line No.: 1 Column: j

Pond sales.

Schedule Page: 310.5 Line No.: 2 Column: b

Settlement adjustment.

Schedule Page: 310.5 Line No.: 2 Column: j

Settlement adjustment.

Schedule Page: 310.5 Line No.: 5 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: 310.5 Line No.: 5 Column: j

Reserve share.

Schedule Page: 310.5 Line No.: 6 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: 310.5 Line No.: 7 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: 310.5 Line No.: 7 Column: j

Reserve share.

Schedule Page: 310.5 Line No.: 8 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: 310.5 Line No.: 9 Column: j

Pond sales.

Schedule Page: 310.5 Line No.: 10 Column: j

Reserve share.

Schedule Page: 310.5 Line No.: 14 Column: j

Reserve share.

Schedule Page: 310.6 Line No.: 1 Column: b

Settlement adjustment.

Schedule Page: 310.6 Line No.: 1 Column: j

Settlement adjustment.

Schedule Page: 310.6 Line No.: 4 Column: j

Reserve share.

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.: 7 Column: b

Settlement adjustment.

Schedule Page: 310.6 Line No.: 7 Column: j

Settlement adjustment.

Schedule Page: 310.6 Line No.: 9 Column: a

This footnote applies to all occurrences of "Sierra Pacific Power Company" on pages 310-311. 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: 310.6 Line No.: 9 Column: j

Reserve share.

Schedule Page: 310.6 Line No.: 12 Column: j

Reserve share.

Schedule Page: 310.6 Line No.: 13 Column: b

Pursuant to FERC Docket No. ER10-2475-006,*et* al. revoking PacifiCorp's market-based rate authority.

Schedule Page: 310.6 Line No.: 13 Column: j

Pursuant to FERC Docket No. ER10-2475-006,*et* al. revoking PacifiCorp's market-based rate authority.

Schedule Page: 310.7 Line No.: 4 Column: b

Pursuant to FERC Docket No. ER10-2475-006,*et* al. revoking PacifiCorp's market-based rate authority.

Schedule Page: 310.7 Line No.: 4 Column: j

Pursuant to FERC Docket No. ER10-2475-006,*et* al. revoking PacifiCorp's market-based rate authority.

Schedule Page: 310.7 Line No.: 5 Column: b

Settlement adjustment.

Schedule Page: 310.7 Line No.: 5 Column: j

Settlement adjustment.

Schedule Page: 310.7 Line No.: 8 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: 310.7 Line No.: 9 Column: b

Pursuant to FERC Docket No. ER10-2475-006,*et* al. revoking PacifiCorp's market-based rate authority.

Schedule Page: 310.7 Line No.: 9 Column: j

Pursuant to FERC Docket No. ER10-2475-006,*et* al. revoking PacifiCorp's market-based rate authority.

Schedule Page: 310.7 Line No.: 13 Column: b

Pursuant to FERC Docket No. ER10-2475-006,*et* al. revoking PacifiCorp's market-based rate authority.

Schedule Page: 310.7 Line No.: 13 Column: j

Pursuant to FERC Docket No. ER10-2475-006,*et* al. revoking PacifiCorp's market-based rate authority.

Schedule Page: 310.8 Line No.: 2 Column: b

Utah Municipal Power Agency - FERC 433 - Contract termination date: June 30, 2017.

Schedule Page: 310.8 Line No.: 7 Column: b

Settlement adjustment.

Schedule Page: 310.8 Line No.: 7 Column: j

Settlement adjustment.

Schedule Page: 310.8 Line No.: 8 Column: b

Pursuant to FERC Docket No. ER10-2475-006,*et* al. revoking PacifiCorp's market-based rate authority.

Schedule Page: 310.8 Line No.: 8 Column: j

Pursuant to FERC Docket No. ER10-2475-006,*et* al. revoking PacifiCorp's market-based rate authority.

Schedule Page: 310.8 Line No.: 9 Column: j

Reflects transactions that did not physically settle.

Schedule Page: 310.8 Line No.: 10 Column: j

Reflects transactions that did not physically settle.

Schedule Page: 310.8 Line No.: 11 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.

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	19,302,289	15,517,011
5	(501) Fuel	820,850,664	893,792,204
6	(502) Steam Expenses	77,494,812	84,614,045
7	(503) Steam from Other Sources	4,387,771	3,980,975
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,357,681	2,351,648
10	(506) Miscellaneous Steam Power Expenses	18,783,155	-15,574,943
11	(507) Rents	497,552	394,702
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	942,673,924	985,075,642
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	8,590,720	8,514,939
16	(511) Maintenance of Structures	29,659,884	30,664,954
17	(512) Maintenance of Boiler Plant	94,238,044	95,031,926
18	(513) Maintenance of Electric Plant	31,617,221	34,835,090
19	(514) Maintenance of Miscellaneous Steam Plant	9,939,070	11,894,236
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	174,044,939	180,941,145
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	1,116,718,863	1,166,016,787
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	8,994,999	8,836,151
45	(536) Water for Power	48,260	121,947
46	(537) Hydraulic Expenses	4,438,179	4,327,999
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses	16,390,065	17,875,790
49	(540) Rents	1,339,115	1,573,497
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	31,210,618	32,735,384
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	400	388
54	(542) Maintenance of Structures	1,157,602	907,301
55	(543) Maintenance of Reservoirs, Dams, and Waterways	4,031,155	1,413,192
56	(544) Maintenance of Electric Plant	2,527,278	1,749,826
57	(545) Maintenance of Miscellaneous Hydraulic Plant	3,013,546	3,016,038
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	10,729,981	7,086,745
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	41,940,599	39,822,129

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 2016/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	315,661	418,092
63	(547) Fuel	252,938,388	272,426,195
64	(548) Generation Expenses	16,727,699	18,238,116
65	(549) Miscellaneous Other Power Generation Expenses	5,300,600	7,745,388
66	(550) Rents	4,007,994	3,491,472
67	TOTAL Operation (Enter Total of lines 62 thru 66)	279,290,342	302,319,263
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	2,825,560	4,228,009
71	(553) Maintenance of Generating and Electric Plant	17,358,571	26,813,693
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	2,135,375	1,481,768
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	22,319,506	32,523,470
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	301,609,848	334,842,733
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	580,289,645	623,108,136
77	(556) System Control and Load Dispatching	1,686,094	1,426,643
78	(557) Other Expenses	43,257,013	48,032,087
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	625,232,752	672,566,866
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	2,085,502,062	2,213,248,515
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	7,696,616	9,280,674
84			
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	7,180,746	6,818,716
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	1,818,514	2,106,756
89	(561.5) Reliability, Planning and Standards Development	1,747,640	1,326,587
90	(561.6) Transmission Service Studies	107,188	106,311
91	(561.7) Generation Interconnection Studies	1,290,346	998,299
92	(561.8) Reliability, Planning and Standards Development Services	7,528,820	7,402,436
93	(562) Station Expenses	3,574,521	3,072,973
94	(563) Overhead Lines Expenses	523,824	409,509
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	130,788,907	148,425,345
97	(566) Miscellaneous Transmission Expenses	3,701,508	2,400,520
98	(567) Rents	2,406,374	2,248,767
99	TOTAL Operation (Enter Total of lines 83 thru 98)	168,365,004	184,596,893
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	967,541	1,186,503
102	(569) Maintenance of Structures	71,460	19,905
103	(569.1) Maintenance of Computer Hardware	163,187	105,911
104	(569.2) Maintenance of Computer Software	290,354	406,743
105	(569.3) Maintenance of Communication Equipment	4,163,332	3,624,514
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	11,581,205	8,037,307
108	(571) Maintenance of Overhead Lines	17,444,207	17,091,353
109	(572) Maintenance of Underground Lines	98,313	51,642
110	(573) Maintenance of Miscellaneous Transmission Plant	116,402	543,682
111	TOTAL Maintenance (Total of lines 101 thru 110)	34,896,001	31,067,560
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	203,261,005	215,664,453

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	10,211,712	11,287,882
135	(581) Load Dispatching	11,608,861	11,746,191
136	(582) Station Expenses	4,455,539	4,235,949
137	(583) Overhead Line Expenses	7,582,880	6,808,598
138	(584) Underground Line Expenses	1,120	6,628
139	(585) Street Lighting and Signal System Expenses	248,347	223,951
140	(586) Meter Expenses	6,053,312	6,584,411
141	(587) Customer Installations Expenses	13,509,277	10,551,937
142	(588) Miscellaneous Expenses	4,583,209	4,670,374
143	(589) Rents	3,318,918	3,315,582
144	TOTAL Operation (Enter Total of lines 134 thru 143)	61,573,175	59,431,503
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	5,375,453	5,710,663
147	(591) Maintenance of Structures	1,997,387	2,230,204
148	(592) Maintenance of Station Equipment	10,617,895	11,414,124
149	(593) Maintenance of Overhead Lines	80,772,052	91,628,672
150	(594) Maintenance of Underground Lines	25,704,585	22,910,745
151	(595) Maintenance of Line Transformers	1,075,858	922,335
152	(596) Maintenance of Street Lighting and Signal Systems	3,239,309	3,252,544
153	(597) Maintenance of Meters	5,970	4,294,012
154	(598) Maintenance of Miscellaneous Distribution Plant	6,136,247	5,240,622
155	TOTAL Maintenance (Total of lines 146 thru 154)	134,924,756	147,603,921
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	196,497,931	207,035,424
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	2,334,844	1,739,975
160	(902) Meter Reading Expenses	18,089,729	17,341,069
161	(903) Customer Records and Collection Expenses	48,583,852	52,023,964
162	(904) Uncollectible Accounts	12,228,903	10,227,550
163	(905) Miscellaneous Customer Accounts Expenses	1,949,683	33,442
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	83,187,011	81,366,000

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	278,714	271,770
168	(908) Customer Assistance Expenses	143,987,121	132,301,137
169	(909) Informational and Instructional Expenses	3,093,817	3,123,200
170	(910) Miscellaneous Customer Service and Informational Expenses	54,913	15,904
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	147,414,565	135,712,011
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	72,807,417	78,097,396
182	(921) Office Supplies and Expenses	8,563,731	8,563,778
183	(Less) (922) Administrative Expenses Transferred-Credit	33,233,808	37,773,122
184	(923) Outside Services Employed	14,997,016	16,829,096
185	(924) Property Insurance	14,265,351	15,938,310
186	(925) Injuries and Damages	1,256,342	5,349,612
187	(926) Employee Pensions and Benefits		
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	25,261,821	22,275,686
190	(929) (Less) Duplicate Charges-Cr.	3,584,897	5,386,124
191	(930.1) General Advertising Expenses	1,818	319
192	(930.2) Miscellaneous General Expenses	2,346,536	2,386,938
193	(931) Rents	4,735,239	4,960,462
194	TOTAL Operation (Enter Total of lines 181 thru 193)	107,416,566	111,242,351
195	Maintenance		
196	(935) Maintenance of General Plant	22,216,334	22,974,990
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	129,632,900	134,217,341
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	2,845,495,474	2,987,243,744

Schedule Page: 320 Line No.: 10 Column: c

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.: 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, 2016 and 2015, pensions and benefits expense was $113,808,905 and $124,649,217, 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 2016/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	Power Purchases:					
2	3Degrees Group, Inc.	OS		NA	NA	NA
3	Apple, Inc.	LU		NA	NA	NA
4	Arizona Electric Power Cooperative	AD		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	Avangrid Renewables, LLC	AD		NA	NA	NA
9	Avangrid Renewables, LLC	SF		NA	NA	NA
10	Avista Corporation	SF		NA	NA	NA
11	BC Solar, LLC	LU		NA	NA	NA
12	BP Energy Company	SF		NA	NA	NA
13	Ballard Hog Farms Inc.	AD		NA	NA	NA
14	Ballard Hog Farms Inc.	LU		0.037	0.03	0.03
	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
					81,797	81,797	2
7,493				560,487		560,487	3
74					1,517	1,517	4
4,800				147,588		147,588	5
32,025				717,362		717,362	6
129,392				2,595,724	154,740	2,750,464	7
					320	320	8
1,845,590				42,916,390		42,916,390	9
145,339				2,652,162	7,076	2,659,238	10
472				27,024		27,024	11
587,139				12,736,726		12,736,726	12
19					1,145	1,145	13
278			5,784	12,494		18,278	14
11,939,781	5,901,498	6,217,758	57,516,408	566,302,353	-43,529,116	580,289,645	

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 2016/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	Basin Electric Power Cooperative	SF		NA	NA	NA
2	Beaver City Corporation	LF		NA	NA	NA
3	Bell Mountain Hydro, LLC	LU		NA	NA	NA
4	Beryl Solar, LLC	LU		3	3	0.7
5	Big Top, LLC	LU		NA	NA	NA
6	Biomass One, L.P.	LU		NA	NA	NA
7	Birch Power Company, Inc.	AD		NA	NA	NA
8	Birch Power Company, Inc.	LU		NA	NA	NA
9	Black Cap Solar, LLC	LU		NA	NA	NA
10	Black Hills Power, Inc.	SF		NA	NA	NA
11	Bonneville Power Administration	LF		NA	NA	NA
12	Bonneville Power Administration	OS		NA	NA	NA
13	Bonneville Power Administration	SF		NA	NA	NA
14	Bourdet, Peter M.	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)	
68,288				1,580,302		1,580,302	1
55				4,409		4,409	2
759				61,809		61,809	3
5,915			407,685	265,601		673,286	4
3,899				286,480		286,480	5
159,261				11,661,538	2,595,743	14,257,281	6
333					20,699	20,699	7
11,317				712,449		712,449	8
660				16,031		16,031	9
8,085				288,987		288,987	10
					10,198	10,198	11
					113,235	113,235	12
640,180				9,478,550	45,231	9,523,781	13
221				5,298		5,298	14
11,939,781	5,901,498	6,217,758	57,516,408	566,302,353	-43,529,116	580,289,645	

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 2016/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.

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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	Box Canyon Limited Partnership	LU		2.921	4.2	2.5
2	Brigham City Corporation	SF		NA	NA	NA
3	Brigham Young University - Idaho	AD		NA	NA	NA
4	Brigham Young University - Idaho	IU		NA	NA	NA
5	Brookfield Energy Marketing L.P.	SF		NA	NA	NA
6	Buckhorn Solar, LLC	LU		0.5	0.54	0.29
7	Butter Creek Power, LLC	LU		NA	NA	NA
8	C Drop Hydro, LLC	LU		NA	NA	NA
9	CDM Hydroelectric Company	LU		NA	NA	NA
10	California Independent System Operator	AD		NA	NA	NA
11	California Independent System Operator	SF		NA	NA	NA
12	Calpine Energy Services, L.P.	SF		NA	NA	NA
13	Cameron A. Curtiss	LU		NA	NA	NA
14	Cargill Power Markets, LLC	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)	
23,912			278,289	3,225,688		3,503,977	1
				43,248		43,248	2
					165,876	165,876	3
39,319				2,041,726		2,041,726	4
800				13,000		13,000	5
5,694			401,593	255,644		657,237	6
11,626				849,453		849,453	7
2,539				191,628		191,628	8
26,490				1,663,034		1,663,034	9
-8,164					-431,047	-431,047	10
1,873				85,435		85,435	11
62,973				1,970,211		1,970,211	12
83				6,275		6,275	13
538,726				12,684,690		12,684,690	14
11,939,781	5,901,498	6,217,758	57,516,408	566,302,353	-43,529,116	580,289,645	

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 2016/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	Cedar Valley Solar, LLC	LU		2.4	2.3	0.2
2	Central Oregon Irrigation District	LU		3.5	3.4	2.2
3	Chevron U.S.A. Inc.	LU		NA	NA	NA
4	Chopin Wind LLC	LU		NA	NA	NA
5	City of Albany	LU		NA	NA	NA
6	City of Astoria	LU		NA	NA	NA
7	City of Buffalo	LU		NA	NA	NA
8	City of Burbank	SF		NA	NA	NA
9	City of Hurricane	LF		NA	NA	NA
10	City of Lehi	IF		NA	NA	NA
11	City of Portland, Water Bureau	LU		NA	NA	NA
12	City of Preston Idaho	LU		NA	NA	NA
13	City of Redding	SF		NA	NA	NA
14	Clatskanie People's Utility District	SF		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,410			333,093	153,106		486,199	1
34,651			357,837	3,480,736		3,838,573	2
42,051				576,848		576,848	3
9,671				471,389		471,389	4
1,271				96,027		96,027	5
29				967		967	6
1,893				50,537		50,537	7
1,200				39,500		39,500	8
1,949				126,653		126,653	9
4				405		405	10
112				8,435		8,435	11
3,003				175,521		175,521	12
710				6,780		6,780	13
2,655				48,739		48,739	14
11,939,781	5,901,498	6,217,758	57,516,408	566,302,353	-43,529,116	580,289,645	

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	Commercial Energy Management Inc.	LU		NA	NA	NA
2	ConocoPhillips Company	SF		NA	NA	NA
3	Consolidated Irrigation Company	LU		NA	NA	NA
4	Cottonwood Hydro, LLC	IU		NA	NA	NA
5	Crook County Solar 1, LLC	LU		NA	NA	NA
6	Deschutes Valley Water District	LU		5.689	4.1	3.1
7	Deseret Generation & Transmission Coop	LF		60	91	63
8	Dorena Hydro, LLC	LU		NA	NA	NA
9	Douglas County	LU		0.7	1.2	0.8
10	Douglas County, Inc.	LU		NA	NA	NA
11	Draper Irrigation Company	IU		NA	NA	NA
12	Dry Creek LLC	LU		NA	NA	NA
13	eBay Inc.	LU		NA	NA	NA
14	EDF Trading North America, LLC	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)	
1,640				92,697		92,697	1
8,000				182,580		182,580	2
2,195				105,056		105,056	3
3,144				152,582		152,582	4
1,235				29,377		29,377	5
30,105			564,134	3,826,371		4,390,505	6
280,826			16,754,873	5,998,832	4,345,631	27,099,336	7
11,121				839,421		839,421	8
7,240			72,977	1,033,126		1,106,103	9
4,974				100,096		100,096	10
325				20,177		20,177	11
11,133				674,176		674,176	12
876				62,255		62,255	13
2,626,399				63,543,899		63,543,899	14
11,939,781	5,901,498	6,217,758	57,516,408	566,302,353	-43,529,116	580,289,645	

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 2016/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	El Paso Electric Company	SF		NA	NA	NA
2	Element Markets, LLC	OS		NA	NA	NA
3	Enterprise Solar, LLC	LU		NA	NA	NA
4	Eugene Water & Electric Board	SF		NA	NA	NA
5	Eurus Combine Hills I, LLC	LU		NA	NA	NA
6	Evergreen BioPower, LLC	LU		NA	NA	NA
7	Exelon Generation Company, LLC	AD		NA	NA	NA
8	Exelon Generation Company, LLC	IF		NA	NA	NA
9	Exelon Generation Company, LLC	SF		NA	NA	NA
10	ExxonMobil Production Company	LU		NA	NA	NA
11	Falls Creek H.P. Limited Partnership	LU		2.7	3.2	2
12	Farm Power Misty Meadow, LLC	LU		NA	NA	NA
13	Farmers Irrigation District	LU		NA	NA	NA
14	Fillmore City Corporation	LF		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		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)	
9,519				184,691	937	185,628	1
					29,565	29,565	2
140,268				4,497,225		4,497,225	3
20,917				446,004		446,004	4
116,763				5,541,593		5,541,593	5
50,268				3,460,539		3,460,539	6
75					3,108	3,108	7
122,904				4,827,885		4,827,885	8
632,329				12,225,765		12,225,765	9
265				11,023		11,023	10
17,739			228,727	2,288,360		2,517,087	11
2,409				186,344		186,344	12
21,156				1,473,372		1,473,372	13
182				19,768		19,768	14
11,939,781	5,901,498	6,217,758	57,516,408	566,302,353	-43,529,116	580,289,645	

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 2016/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	Finley BioEnergy, LLC	LU		NA	NA	NA
2	Flathead Electric Cooperative, Inc.	LF		NA	NA	NA
3	Foote Creek II, LLC	LU		NA	NA	NA
4	Foote Creek III, LLC	LU		NA	NA	NA
5	Four Brothers Solar, LLC	LU		NA	NA	NA
6	Four Corners Windfarm, LLC	LU		NA	NA	NA
7	Four Mile Canyon Windfarm, LLC	LU		NA	NA	NA
8	George DeRuyter & Sons Dairy	LU		0.11	0.1	0.1
9	Georgetown Irrigation Company	LU		NA	NA	NA
10	Grand Valley Power	LF		NA	NA	NA
11	Granite Mountain Holdings LLC	LU		NA	NA	NA
12	Granite Peak Solar, LLC	AD		NA	NA	NA
13	Granite Peak Solar, LLC	LU		3	3	0.5
14	Greenville Solar, LLC	LU		2.3	2.2	0.4
	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)	
27,114				2,044,395		2,044,395	1
422					8,001	8,001	2
5,446				103,549		103,549	3
75,950				1,631,017		1,631,017	4
277,275				9,344,319		9,344,319	5
28,062				2,053,690		2,053,690	6
25,264				1,851,456		1,851,456	7
979			3,420	32,954		36,374	8
1,813				111,551		111,551	9
46				10,116		10,116	10
81,525				3,439,175		3,439,175	11
					1,030	1,030	12
5,529			203,655	177,487		381,142	13
3,537			314,576	158,825		473,401	14
11,939,781	5,901,498	6,217,758	57,516,408	566,302,353	-43,529,116	580,289,645	

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 2016/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	Gridforce Energy Management	SF		NA	NA	NA
2	Guzman Renewables Energy Partners LLC	SF		NA	NA	NA
3	Harold Foster & Robert Walker	LU		NA	NA	NA
4	Hermiston Generating Company, L.P.	AD		NA	NA	NA
5	Hermiston Generating Company, L.P.	LU		91.2	116	75.7
6	Idaho Falls, City of	AD		NA	NA	NA
7	Idaho Falls, City of	LU		NA	NA	NA
8	Idaho Power Company	SF		NA	NA	NA
9	Intermountain Power Agency	LU		NA	NA	NA
10	Iron Springs Solar, LLC	LU		NA	NA	NA
11	J Bar 9 Ranch, Inc.	LU		NA	NA	NA
12	Jake Amy	LU		NA	NA	NA
13	Joseph Community Solar LLC	LU		NA	NA	NA
14	Kettle Butte Digester 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)	
44					1,219	1,219	1
2,809				95,639		95,639	2
691				27,843		27,843	3
-1					244	244	4
547,251			18,964,289	9,527,897	129,784	28,621,970	5
					-43,265	-43,265	6
51,838					1,226,190	1,226,190	7
11,053				150,167	836	151,003	8
122,424				3,318,535		3,318,535	9
114,477				4,775,689		4,775,689	10
53				3,166		3,166	11
1,356				80,880		80,880	12
685				15,747		15,747	13
					-3,177	-3,177	14
11,939,781	5,901,498	6,217,758	57,516,408	566,302,353	-43,529,116	580,289,645	

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	Kettle Butte Digester LLC	LU		NA	NA	NA
2	Klamath Falls Solar 1 LLC	LU		NA	NA	NA
3	Lacomb Irrigation District	LU		NA	NA	NA
4	Laho Solar, LLC	LU		3	3	0.7
5	Latigo Wind Park, LLC	LU		NA	NA	NA
6	Los Angeles Dept. of Water and Power	SF		NA	NA	NA
7	Lower Valley Energy, Inc.	IU		NA	NA	NA
8	Lower Valley Energy, Inc.	LU		NA	NA	NA
9	Loyd Fery	LU		NA	NA	NA
10	Macquarie Energy LLC	SF		NA	NA	NA
11	Marsh Valley Hydro Electric Company	LU		NA	NA	NA
12	Meadow Creek Project Company LLC	LU		NA	NA	NA
13	Middle Fork Irrigation District	LU		NA	NA	NA
14	Milford Flat Solar, 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 2016/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)	
6,324				463,201		463,201	1
880				37,305		37,305	2
5,048				101,436	40,015	141,451	3
6,082			203,889	195,244		399,133	4
111,184				6,336,211		6,336,211	5
10,663				361,792		361,792	6
5,876				298,783		298,783	7
1,488				76,878		76,878	8
336				10,094		10,094	9
138,268				3,187,959		3,187,959	10
4,729				297,147		297,147	11
277,877				19,317,496		19,317,496	12
25,453				1,748,796		1,748,796	13
6,074				146,225		146,225	14
11,939,781	5,901,498	6,217,758	57,516,408	566,302,353	-43,529,116	580,289,645	

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 2016/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	Mink Creek Hydro LLC	LU		NA	NA	NA
2	Monsanto Company	AD		NA	NA	NA
3	Monsanto Company	IU		NA	NA	NA
4	Morgan City Corporation	LF		NA	NA	NA
5	Morgan Stanley Capital Group Inc.	SF		NA	NA	NA
6	Mountain Energy, Inc.	LU		NA	NA	NA
7	Mountain Wind Power II, LLC	LU		NA	NA	NA
8	Mountain Wind Power, LLC	LU		NA	NA	NA
9	Municipal Energy Agency of Nebraska	SF		NA	NA	NA
10	Nevada Power Company	AD		NA	NA	NA
11	Nevada Power Company	SF		NA	NA	NA
12	NextEra Energy Power Marketing, LLC	AD		NA	NA	NA
13	NextEra Energy Power Marketing, LLC	SF		NA	NA	NA
14	Nichols Gap Limited Partnership	LU		0.4	0.6	0.3
	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)	
9,290				568,222		568,222	1
					293,365	293,365	2
					20,000,000	20,000,000	3
10				898		898	4
280,658				8,853,579		8,853,579	5
80				6,014		6,014	6
211,253				13,773,713		13,773,713	7
160,884				9,021,283		9,021,283	8
3,944				131,002		131,002	9
					-795	-795	10
17,251				406,715	92,769	499,484	11
					-11,950	-11,950	12
1,800				33,620		33,620	13
3,467			42,172	466,259		508,431	14
11,939,781	5,901,498	6,217,758	57,516,408	566,302,353	-43,529,116	580,289,645	

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 2016/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	Nicholson's Sunny Bar Ranch	LU		NA	NA	NA
2	NorthWestern Corporation	OS		NA	NA	NA
3	NorthWestern Corporation	SF		NA	NA	NA
4	Nucor Corporation	IF		NA	NA	NA
5	O.J. Power Company	LU		NA	NA	NA
6	OSLH, LLC	LU		NA	NA	NA
7	Obsidian Renewables, LLC	LU		NA	NA	NA
8	Old Mill Solar, LLC	LU		NA	NA	NA
9	Oregon Environmental Industries, LLC	LU		NA	NA	NA
10	Oregon Institute of Technology	LU		NA	NA	NA
11	Oregon Solar Incentive	LU		NA	NA	NA
12	Oregon State University	LU		NA	NA	NA
13	Oregon Trail Windfarm, LLC	LU		NA	NA	NA
14	Pacific Canyon Windfarm, 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)	
1,579				98,469		98,469	1
796				13,582		13,582	2
7,707				116,354	6,322	122,676	3
					7,129,800	7,129,800	4
379				20,318		20,318	5
1				35		35	6
910				22,021		22,021	7
9,015				659,436		659,436	8
21,560				1,477,968		1,477,968	9
315				5,852		5,852	10
11,013				259,618		259,618	11
4				67		67	12
21,616				1,583,947		1,583,947	13
17,859				1,313,339		1,313,339	14
11,939,781	5,901,498	6,217,758	57,516,408	566,302,353	-43,529,116	580,289,645	

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 2016/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	Paul Luckey	LU		NA	NA	NA
2	Pavant Solar II, LLC	LU		NA	NA	NA
3	Pavant Solar III, LLC	LU		NA	NA	NA
4	Pavant Solar, LLC	LU		NA	NA	NA
5	Pioneer Wind Park	LU		NA	NA	NA
6	Platte River Power Authority	AD		NA	NA	NA
7	Platte River Power Authority	SF		NA	NA	NA
8	Portland General Electric Company	AD		NA	NA	NA
9	Portland General Electric Company	LF		NA	NA	NA
10	Portland General Electric Company	SF		NA	NA	NA
11	Power County Wind Park North, LLC	LU		NA	NA	NA
12	Power County Wind Park South, LLC	LU		NA	NA	NA
13	Powerex Corporation	OS		NA	NA	NA
14	Powerex Corporation	SF		NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
250				11,947		11,947	1
8,509				176,112		176,112	2
96				5,072		5,072	3
109,951				3,736,048		3,736,048	4
81,794				2,949,562		2,949,562	5
					-2,645	-2,645	6
3,624					71,446	71,446	7
					-52,594	-52,594	8
11,941					187,000	187,000	9
81,437				1,738,575	10,898	1,749,473	10
63,878				4,544,696		4,544,696	11
54,521				3,878,177		3,878,177	12
195				8,515		8,515	13
564,807				16,236,708		16,236,708	14
11,939,781	5,901,498	6,217,758	57,516,408	566,302,353	-43,529,116	580,289,645	

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 2016/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	Provo City Corporation	LF		NA	NA	NA
2	Public Service Company of Colorado	SF		NA	NA	NA
3	Public Service Company of New Mexico	AD		NA	NA	NA
4	Public Service Company of New Mexico	SF		NA	NA	NA
5	PUD No. 1 of Chelan County	SF		NA	NA	NA
6	PUD No. 1 of Clark County	SF		NA	NA	NA
7	PUD No. 1 of Cowlitz County	OS		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)	
48				4,219		4,219	1
247,748				5,046,406		5,046,406	2
25					675	675	3
63,778				1,519,364	120	1,519,484	4
72,351				1,469,506	1,756	1,471,262	5
15,352				258,080		258,080	6
					-128,733	-128,733	7
62,384				2,144,642		2,144,642	8
248,655					3,650,764	3,650,764	9
26,474				455,360	606	455,966	10
70,860				989,520		989,520	11
					-179,661	-179,661	12
91,474					765,175	765,175	13
149					3,754	3,754	14
11,939,781	5,901,498	6,217,758	57,516,408	566,302,353	-43,529,116	580,289,645	

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	Puget Sound Energy, Inc.	AD		NA	NA	NA
2	Puget Sound Energy, Inc.	SF		NA	NA	NA
3	Quichapa	LU		NA	NA	NA
4	RES Ag - Oak Lea LLC	LU		NA	NA	NA
5	Rainbow Energy Marketing Corporation	SF		NA	NA	NA
6	Renewable Power Strategies	OS		NA	NA	NA
7	Rock River 1, LLC	AD		NA	NA	NA
8	Rock River 1, LLC	LU		NA	NA	NA
9	Roseburg Forest Products Company	LU		NA	NA	NA
10	Roseburg LFG Energy, LLC	LU		NA	NA	NA
11	Rough & Ready Lumber Company	LU		NA	NA	NA
12	Roush Hydro Inc.	LU		NA	NA	NA
13	Sacramento Municipal Utility District	AD		NA	NA	NA
14	Sacramento Municipal Utility District	SF		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					11,950	11,950	1
212,591				3,476,252	11,942	3,488,194	2
761				75,911		75,911	3
488				37,674		37,674	4
38,399				1,266,368		1,266,368	5
					310,166	310,166	6
43							7
145,789				5,172,608		5,172,608	8
65,223				3,677,245		3,677,245	9
12,303				927,566		927,566	10
302				22,936		22,936	11
271				8,093		8,093	12
					135,779	135,779	13
2,400				70,200		70,200	14
11,939,781	5,901,498	6,217,758	57,516,408	566,302,353	-43,529,116	580,289,645	

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 2016/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	Salt River Project	SF		NA	NA	NA
2	Sand Ranch Windfarm, LLC	LU		NA	NA	NA
3	Santiam Water Control District	LU		0.2	0.2	0.2
4	Seattle City Light	SF		NA	NA	NA
5	Sempra Generation, LLC	SF		NA	NA	NA
6	Shell Energy North America (US), L.P.	AD		NA	NA	NA
7	Shell Energy North America (US), L.P.	SF		NA	NA	NA
8	Shiloh Warm Springs Ranch, LLC	LU		NA	NA	NA
9	Sierra Pacific Power Company	SF		NA	NA	NA
10	Slate Creek Hydro Company, Inc.	LU		1.89	2.2	0.7
11	Solwatt LLC	LU		NA	NA	NA
12	South Utah Valley Electric	LF		NA	NA	NA
13	Southern California Edison Company	AD		NA	NA	NA
14	Southern California Edison 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)	
342,019				8,640,119	2,663	8,642,782	1
21,179				1,558,379		1,558,379	2
1,434			13,426	173,171		186,597	3
112,990				2,047,923	4,736	2,052,659	4
185,350				3,326,132		3,326,132	5
271					9,369	9,369	6
547,514				12,458,136		12,458,136	7
712				44,424		44,424	8
275				3,894	6,639	10,533	9
10,537			173,288	1,291,223		1,464,511	10
810				19,109		19,109	11
21				1,456		1,456	12
37					776	776	13
153				2,769		2,769	14
11,939,781	5,901,498	6,217,758	57,516,408	566,302,353	-43,529,116	580,289,645	

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 2016/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	Spanish Fork Wind Park 2, LLC	AD		NA	NA	NA
2	Spanish Fork Wind Park 2, LLC	LU		NA	NA	NA
3	Sprague Hydro LLC	LU		0.532	0.6	0.3
4	St. Anthony Hydro, LLC	AD		NA	NA	NA
5	St. Anthony Hydro, LLC	LU		NA	NA	NA
6	Stahlbush Island Farms, Inc.	IU		NA	NA	NA
7	SunE DB 24, LLC	AD		0.962	NA	NA
8	SunE DB 24, LLC	LU		2.724	NA	NA
9	SunE DB18, LLC	LU		2.8	5.3	4.8
10	SunE Solar XVII Project1, LLC	LU		2.7	2.8	1
11	SunE Solar XVII Project2, LLC	LU		2.8	2.8	1.1
12	SunE Solar XVII Project3, LLC	LU		2.8	2.8	1.2
13	Sunnyside Cogeneration Associates	LU		50	53	48
14	Surprise Valley Electrification Corp.	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)	
					236,271	236,271	1
48,248				2,701,645		2,701,645	2
3,636			56,838	482,870		539,708	3
					-1	-1	4
5,180				309,130		309,130	5
1,051				18,512		18,512	6
173					8,612	8,612	7
6,988			132,553	224,318		356,871	8
7,270			390,986	326,420		717,406	9
6,980			373,168	313,395		686,563	10
7,241			378,866	325,122		703,988	11
7,130			194,018	228,870		422,888	12
400,996			10,632,743	16,869,047		27,501,790	13
1,873				85,147		85,147	14
11,939,781	5,901,498	6,217,758	57,516,408	566,302,353	-43,529,116	580,289,645	

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 2016/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	Swalley Irrigation District	LU		NA	NA	NA
2	TMF Biofuels, LLC	LU		NA	NA	NA
3	Tacoma Power	SF		NA	NA	NA
4	Talen Energy Marketing, LLC	OS		NA	NA	NA
5	Talen Energy Marketing, LLC	SF		NA	NA	NA
6	Tata Chemicals (Soda Ash) Partners	LU		NA	NA	NA
7	Tenaska Power Services Co.	AD		NA	NA	NA
8	Tenaska Power Services Co.	SF		NA	NA	NA
9	Tesoro Refining & Marketing Co, LLC	AD		NA	NA	NA
10	Tesoro Refining & Marketing Co, LLC	LU		NA	NA	NA
11	Thayn Hydro LLC	LU		NA	NA	NA
12	The Confederated Tribe of Warm Springs	LU		NA	NA	NA
13	The Energy Authority, Inc.	SF		NA	NA	NA
14	Three Buttes Windpower, 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)	
2,304				173,807		173,807	1
15,462				1,101,501		1,101,501	2
172,108				3,961,023	2,110	3,963,133	3
400				12,260		12,260	4
67,941				1,225,812		1,225,812	5
3,839				122,543		122,543	6
-95					-2,096	-2,096	7
14,477				317,252		317,252	8
					338	338	9
19,573				476,230		476,230	10
2,477				93,461		93,461	11
331				7,589		7,589	12
74,313				1,581,981		1,581,981	13
333,872				21,250,160		21,250,160	14
11,939,781	5,901,498	6,217,758	57,516,408	566,302,353	-43,529,116	580,289,645	

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 2016/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	Three Peaks Power, LLC	LU		NA	NA	NA
2	Three Sisters Irrigation District	LU		NA	NA	NA
3	Threemile Canyon Wind I, LLC	LU		NA	NA	NA
4	Tooele Army Depot	LU		NA	NA	NA
5	Top of The World Wind Energy LLC	LU		NA	NA	NA
6	TransAlta Energy Marketing (U.S.) Inc.	AD		NA	NA	NA
7	TransAlta Energy Marketing (U.S.) Inc.	SF		NA	NA	NA
8	Tri-State Generation and Transmission	LF		25	25	14
9	Tri-State Generation and Transmission	SF		NA	NA	NA
10	Tucson Electric Power Company	SF		NA	NA	NA
11	Turlock Irrigation District	SF		NA	NA	NA
12	U.S. Dept of the Interior	LU		NA	NA	NA
13	UNS Electric, Inc.	SF		NA	NA	NA
14	US Magnesium LLC	LF		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		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)	
8,842				235,041		235,041	1
2,601				131,789		131,789	2
20,700				1,547,751		1,547,751	3
176				4,890		4,890	4
651,049				42,967,632		42,967,632	5
-375					-10,388	-10,388	6
410,510				11,103,278		11,103,278	7
96,250			5,940,000	3,054,013		8,994,013	8
5,693				122,745	4,973	127,718	9
30,559				778,461	1,082	779,543	10
580				6,468		6,468	11
29				1,841		1,841	12
984				22,552		22,552	13
					6,706,025	6,706,025	14
11,939,781	5,901,498	6,217,758	57,516,408	566,302,353	-43,529,116	580,289,645	

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.

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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	United States Air Force at Hill Base	LU		NA	NA	NA
2	Utah Municipal Power Agency	IU		NA	NA	NA
3	Utah Red Hills Renewable Park, LLC	AD		NA	NA	NA
4	Utah Red Hills Renewable Park, LLC	LU		NA	NA	NA
5	Vitol Inc.	SF		NA	NA	NA
6	Wagon Trail, LLC	LU		NA	NA	NA
7	Ward Butte Windfarm, LLC	LU		NA	NA	NA
8	Wasatch Integrated Waste Mgmt District	LU		0.5	0.5	0.145
9	Weber County	LU		NA	NA	NA
10	Western Area Power Administration	LF		NA	NA	NA
11	Western Area Power Administration	SF		NA	NA	NA
12	Wolverine Creek Energy, LLC	LU		NA	NA	NA
13	Yakima-Tieton Irrigation District	LU		0.8	1.2	1
14	CA Greenhouse Gas Allowance Purchases			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 2016/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)	
16,345				831,197		831,197	1
87,508				5,240,854		5,240,854	2
					-5,986	-5,986	3
208,081				5,013,087		5,013,087	4
161,800				3,508,160		3,508,160	5
6,129				450,665		450,665	6
16,909				1,237,574		1,237,574	7
1,800			69,403	80,804		150,207	8
2,691				142,081		142,081	9
14,229					399,965	399,965	10
26,511				472,572	90,986	563,558	11
174,814				10,243,985		10,243,985	12
7,171			24,126	241,446		265,572	13
					5,857,872	5,857,872	14
11,939,781	5,901,498	6,217,758	57,516,408	566,302,353	-43,529,116	580,289,645	

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	Settlement/Reserves			NA	NA	NA
2	Netting - Trading			NA	NA	NA
3	Regulatory Energy Cost Deferrals			NA	NA	NA
4	Netting - Bookouts			NA	NA	NA
5	Accrual			NA	NA	NA
6						
7	Power Exchanges:					
8	Arizona Public Service Company	EX	307	NA	NA	NA
9	Avista Corporation	EX	T-13	NA	NA	NA
10	Bonneville Power Administration	AD	237	NA	NA	NA
11	Bonneville Power Administration	AD	T-12	NA	NA	NA
12	Bonneville Power Administration	EX	237	NA	NA	NA
13	Bonneville Power Administration	EX	519	NA	NA	NA
14	Bonneville Power Administration	EX	T-12	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)	
					-207,000	-207,000	1
					-657,254	-657,254	2
					80,815,989	80,815,989	3
-6,130,887					-143,519,619	-143,519,619	4
11					2,119,910	2,119,910	5
							6
							7
	568,701	570,837			35,804	35,804	8
	1,617						9
	77,775	109,709			-3,329,833	-3,329,833	10
	-245				-4,964	-4,964	11
		19,696			-49,014	-49,014	12
	102,766	100,567			95,026	95,026	13
	7,181				244,744	244,744	14
11,939,781	5,901,498	6,217,758	57,516,408	566,302,353	-43,529,116	580,289,645	

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	T-13	NA	NA	NA
2	California Independent System Operator	AD	T-11	NA	NA	NA
3	California Independent System Operator	AD	T-12	NA	NA	NA
4	California Independent System Operator	EX	T-11	NA	NA	NA
5	California Independent System Operator	EX	T-12	NA	NA	NA
6	Emerald People's Utility District	EX	351	NA	NA	NA
7	Eugene Water & Electric Board	EX	T-12	NA	NA	NA
8	Idaho Power Company	EX	380	NA	NA	NA
9	Los Angeles Dept. of Water and Power	EX	OV-1	NA	NA	NA
10	Milford Wind Corridor Phase I, LLC	EX	OV-1	NA	NA	NA
11	Milford Wind Corridor Phase II, LLC	EX	OV-1	NA	NA	NA
12	NorthWestern Corporation	EX	160	NA	NA	NA
13	Portland General Electric Company	EX	T-13	NA	NA	NA
14	Public Service Company of Colorado	EX	319	NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
	208,026	9,838					1
					-4,973,694	-4,973,694	2
					4,708,910	4,708,910	3
					-8,685,215	-8,685,215	4
	1,435,283	2,377,735			-35,540,037	-35,540,037	5
		811			-20,280	-20,280	6
	20,699	19,917			22,420	22,420	7
	154,800	123,128					8
	4,406				253,691	253,691	9
		2,852			-163,534	-163,534	10
		1,554			-90,157	-90,157	11
	1,635						12
	62,388						13
	3,612						14
11,939,781	5,901,498	6,217,758	57,516,408	566,302,353	-43,529,116	580,289,645	

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 2016/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Public Service Company of Colorado	EX	334	NA	NA	NA
2	PUD No. 1 of Cowlitz County	EX	442	NA	NA	NA
3	Seattle City Light	EX	T-12	NA	NA	NA
4	Tri-State Generation and Transmission	EX	319	NA	NA	NA
5	Warm Springs Power Enterprises	EX	T-11	NA	NA	NA
6	Western Area Power Administration	AD	LAS-4	NA	NA	NA
7	Western Area Power Administration	EX	LAS-4	NA	NA	NA
8	Imbalance Energy Accrual	EX	T-11	NA	NA	NA
9	System Deviation	NA		NA	NA	NA
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)	
	1,316,838	1,313,423			5,400,000	5,400,000	1
	242,716	265,085					2
	369,067	373,339			103,050	103,050	3
	3,590						4
	7,619	2,823			99,795	99,795	5
	886	10,671			-229,511	-229,511	6
	2,003	16,244			-294,619	-294,619	7
	1,310,135	899,529			6,207,773	6,207,773	8
-18,266							9
							10
							11
							12
							13
							14
11,939,781	5,901,498	6,217,758	57,516,408	566,302,353	-43,529,116	580,289,645	

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 renewable portfolio standard requirements.

Schedule Page: 326 Line No.: 4 Column: b
Settlement adjustment.

Schedule Page: 326 Line No.: 4 Column: l
Settlement adjustment.

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: b
Settlement adjustment.

Schedule Page: 326 Line No.: 8 Column: l
Settlement adjustment.

Schedule Page: 326 Line No.: 10 Column: l
Reserve share.

Schedule Page: 326 Line No.: 13 Column: b
Settlement adjustment.

Schedule Page: 326 Line No.: 13 Column: l
Settlement adjustment.

Schedule Page: 326.1 Line No.: 2 Column: b
Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.1 Line No.: 6 Column: l
Non-generation agreement.

Schedule Page: 326.1 Line No.: 7 Column: b
Settlement adjustment.

Schedule Page: 326.1 Line No.: 7 Column: l
Settlement adjustment.

Schedule Page: 326.1 Line No.: 9 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.: 11 Column: b
Bonneville Power Administration - contract termination date: 30 days written notice.

Schedule Page: 326.1 Line No.: 11 Column: l
Ancillary services.

Schedule Page: 326.1 Line No.: 12 Column: b
Secondary, economy and/or non-firm.

Schedule Page: 326.1 Line No.: 12 Column: l
Ancillary services.

Schedule Page: 326.1 Line No.: 13 Column: l
Reserve share.

Schedule Page: 326.2 Line No.: 3 Column: b
Settlement adjustment.

Schedule Page: 326.2 Line No.: 3 Column: l
Settlement adjustment.

Schedule Page: 326.2 Line No.: 10 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.: 10 Column: b

Settlement adjustment.

Schedule Page: 326.2 Line No.: 10 Column: l

Settlement adjustment.

Schedule Page: 326.3 Line No.: 9 Column: b

City of Hurricane - contract termination date: August 31, 2017.

Schedule Page: 326.3 Line No.: 11 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: 326.4 Line No.: 7 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.: 7 Column: b

Deseret Generation and Transmission Co-operative - contract termination date: September 30, 2024.

Schedule Page: 326.4 Line No.: 7 Column: l

Reimbursement to counterparty for operation and maintenance costs at coal fired generating facility located in Vernal, Utah.

Schedule Page: 326.5 Line No.: 1 Column: l

Line loss.

Schedule Page: 326.5 Line No.: 2 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.5 Line No.: 2 Column: l

Purchase of renewable energy credit certificates for renewable portfolio standard requirements.

Schedule Page: 326.5 Line No.: 7 Column: b

Settlement adjustment.

Schedule Page: 326.5 Line No.: 7 Column: l

Settlement adjustment.

Schedule Page: 326.5 Line No.: 14 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.6 Line No.: 2 Column: b

Flathead Electric Cooperative, Inc. - contract termination date: September 30, 2016.

Schedule Page: 326.6 Line No.: 2 Column: l

Line loss.

Schedule Page: 326.6 Line No.: 10 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.6 Line No.: 12 Column: b

Settlement adjustment.

Schedule Page: 326.6 Line No.: 12 Column: l

Settlement adjustment.

Schedule Page: 326.7 Line No.: 1 Column: l

Reserve share.

Schedule Page: 326.7 Line No.: 4 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 403.2 in this Form No. 1 for further information on the Hermiston Generating Plant.

Schedule Page: 326.7 Line No.: 4 Column: b

Settlement adjustment.

Schedule Page: 326.7 Line No.: 4 Column: l

On peak incentive, supplemental dispatch efficiency expense, start-up charges and committee settlements.

Schedule Page: 326.7 Line No.: 5 Column: l

On peak incentive, supplemental dispatch efficiency expense, start-up charges and committee settlements.

Schedule Page: 326.7 Line No.: 6 Column: b
Settlement adjustment.

Schedule Page: 326.7 Line No.: 6 Column: l
Labor, equipment and administration fees associated with hydro project in Idaho Falls, Idaho.

Schedule Page: 326.7 Line No.: 7 Column: l
Labor, equipment and administration fees associated with hydro project in Idaho Falls, Idaho.

Schedule Page: 326.7 Line No.: 8 Column: l
Reserve share.

Schedule Page: 326.7 Line No.: 14 Column: b
Settlement adjustment.

Schedule Page: 326.7 Line No.: 14 Column: l
Settlement adjustment.

Schedule Page: 326.8 Line No.: 3 Column: l
Fixed annual payment.

Schedule Page: 326.8 Line No.: 6 Column: a
This footnote applies to all occurrences of "Los Angeles Dept. of Water and Power" on pages 326-327. Complete name is Los Angeles Department of Water and Power.

Schedule Page: 326.9 Line No.: 2 Column: b
Settlement adjustment.

Schedule Page: 326.9 Line No.: 2 Column: l
Compensation for interruptible service and operating reserves.

Schedule Page: 326.9 Line No.: 3 Column: l
Compensation for interruptible service and operating reserves.

Schedule Page: 326.9 Line No.: 4 Column: b
Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.9 Line No.: 10 Column: a
This footnote applies to all occurrences of "Nevada Power Company" on pages 326-327. 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: 326.9 Line No.: 10 Column: b
Settlement adjustment.

Schedule Page: 326.9 Line No.: 10 Column: l
Settlement adjustment.

Schedule Page: 326.9 Line No.: 11 Column: l
Line loss.

Schedule Page: 326.9 Line No.: 12 Column: b
Settlement adjustment.

Schedule Page: 326.9 Line No.: 12 Column: l
Settlement adjustment.

Schedule Page: 326.10 Line No.: 2 Column: b
Secondary, economy and/or non-firm.

Schedule Page: 326.10 Line No.: 3 Column: l
Reserve share.

Schedule Page: 326.10 Line No.: 4 Column: l
Ancillary services.

Schedule Page: 326.11 Line No.: 6 Column: b
Settlement adjustment.

Schedule Page: 326.11 Line No.: 6 Column: l
Line loss.

Schedule Page: 326.11 Line No.: 7 Column: l
Line loss.

Schedule Page: 326.11 Line No.: 8 Column: b
Settlement adjustment.
Schedule Page: 326.11 Line No.: 8 Column: l
Operation expense plus amortization of unrecovered costs of Cove Project.
Schedule Page: 326.11 Line No.: 9 Column: b
Portland General Electric Company - contract termination date: Round Butte project no longer operating for power production purposes.
Schedule Page: 326.11 Line No.: 9 Column: l
Operation expense plus amortization of unrecovered costs of Cove Project.
Schedule Page: 326.11 Line No.: 10 Column: l
Reserve share.
Schedule Page: 326.11 Line No.: 13 Column: b
Secondary, economy and/or non-firm.
Schedule Page: 326.12 Line No.: 1 Column: b
Under Electric Service Agreement subject to termination upon timely notification.
Schedule Page: 326.12 Line No.: 3 Column: b
Settlement adjustment.
Schedule Page: 326.12 Line No.: 3 Column: l
Settlement adjustment.
Schedule Page: 326.12 Line No.: 4 Column: l
Line loss.
Schedule Page: 326.12 Line No.: 5 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: 326.12 Line No.: 5 Column: l
Reserve share.
Schedule Page: 326.12 Line No.: 6 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: 326.12 Line No.: 7 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: 326.12 Line No.: 7 Column: b
Secondary, economy and/or non-firm.
Schedule Page: 326.12 Line No.: 7 Column: l
Operating expense, bond interest, amortization and taxes.
Schedule Page: 326.12 Line No.: 8 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: 326.12 Line No.: 8 Column: b
Public Utility District No. 1 of Douglas County - contract termination date: August 31, 2018.
Schedule Page: 326.12 Line No.: 9 Column: l
Operating expense, bond interest, amortization and taxes.
Schedule Page: 326.12 Line No.: 10 Column: l
Reserve share.
Schedule Page: 326.12 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: 326.12 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: 326.12 Line No.: 12 Column: b
Settlement adjustment.

Schedule Page: 326.12 Line No.: 12 Column: l
Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.12 Line No.: 13 Column: l
Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.12 Line No.: 14 Column: l
Reserve share.

Schedule Page: 326.13 Line No.: 1 Column: b
Settlement adjustment.

Schedule Page: 326.13 Line No.: 1 Column: l
Purchase of renewable energy credit certificates for renewable portfolio standard requirements.

Schedule Page: 326.13 Line No.: 2 Column: l
Reserve share.

Schedule Page: 326.13 Line No.: 6 Column: b
Secondary, economy and/or non-firm.

Schedule Page: 326.13 Line No.: 6 Column: l
Purchase of renewable energy credit certificates for renewable portfolio standard requirements.

Schedule Page: 326.13 Line No.: 7 Column: b
Settlement adjustment.

Schedule Page: 326.13 Line No.: 13 Column: b
Settlement adjustment.

Schedule Page: 326.13 Line No.: 13 Column: l
Settlement adjustment.

Schedule Page: 326.14 Line No.: 1 Column: l
Line loss.

Schedule Page: 326.14 Line No.: 4 Column: l
Reserve share.

Schedule Page: 326.14 Line No.: 6 Column: b
Settlement adjustment.

Schedule Page: 326.14 Line No.: 6 Column: l
Settlement adjustment.

Schedule Page: 326.14 Line No.: 9 Column: a
This footnote applies to all occurrences of "Sierra Pacific Power Company" on pages 326-327. 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: 326.14 Line No.: 9 Column: l
Reserve share.

Schedule Page: 326.14 Line No.: 12 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: 326.14 Line No.: 12 Column: b
Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.14 Line No.: 13 Column: b
Settlement adjustment.

Schedule Page: 326.14 Line No.: 13 Column: l
Settlement adjustment.

Schedule Page: 326.15 Line No.: 1 Column: b
Settlement adjustment.

Schedule Page: 326.15 Line No.: 1 Column: l
Settlement adjustment.

Schedule Page: 326.15 Line No.: 4 Column: b
Settlement adjustment.

Schedule Page: 326.15 Line No.: 4 Column: l
Settlement adjustment.
Schedule Page: 326.15 Line No.: 7 Column: b
Settlement adjustment.
Schedule Page: 326.15 Line No.: 7 Column: l
Settlement adjustment.
Schedule Page: 326.16 Line No.: 3 Column: l
Reserve share.
Schedule Page: 326.16 Line No.: 4 Column: b
Secondary, economy and/or non-firm.
Schedule Page: 326.16 Line No.: 7 Column: b
Settlement adjustment.
Schedule Page: 326.16 Line No.: 7 Column: l
Settlement adjustment.
Schedule Page: 326.16 Line No.: 9 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: 326.16 Line No.: 9 Column: b
Settlement adjustment.
Schedule Page: 326.16 Line No.: 9 Column: l
Settlement adjustment.
Schedule Page: 326.16 Line No.: 12 Column: 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: 326.17 Line No.: 6 Column: b
Settlement adjustment.
Schedule Page: 326.17 Line No.: 6 Column: l
Settlement adjustment.
Schedule Page: 326.17 Line No.: 8 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: 326.17 Line No.: 8 Column: b
Tri-State Generation and Transmission Association, Inc. - contract termination date: December 31, 2020.
Schedule Page: 326.17 Line No.: 9 Column: l
Line loss.
Schedule Page: 326.17 Line No.: 10 Column: l
Line loss.
Schedule Page: 326.17 Line No.: 12 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: 326.17 Line No.: 14 Column: b
US Magnesium LLC - contract termination date: December 31, 2017.
Schedule Page: 326.17 Line No.: 14 Column: l
Ancillary services.
Schedule Page: 326.18 Line No.: 1 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: 326.18 Line No.: 3 Column: b
Settlement adjustment.
Schedule Page: 326.18 Line No.: 3 Column: l
Settlement adjustment.
Schedule Page: 326.18 Line No.: 8 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: 326.18 Line No.: 10 Column: b

Western Area Power Administration - contract termination date: May 31, 2022.

Schedule Page: 326.18 Line No.: 10 Column: l

Line loss.

Schedule Page: 326.18 Line No.: 11 Column: l

Reserve share.

Schedule Page: 326.18 Line No.: 14 Column: l

Purchases of greenhouse gas allowances for compliance with the California Air Resources Board greenhouse gas cap-and-trade program.

Schedule Page: 326.19 Line No.: 1 Column: l

Settlement associated with insufficient line loss compensation in past.

Schedule Page: 326.19 Line No.: 2 Column: l

Reflects transactions that did not physically settle.

Schedule Page: 326.19 Line No.: 3 Column: l

Deferrals and associated amortization under various energy cost adjustment mechanisms.

Schedule Page: 326.19 Line No.: 4 Column: l

Reflects transactions that did not physically settle.

Schedule Page: 326.19 Line No.: 5 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: 326.19 Line No.: 8 Column: l

Exchange energy expense.

Schedule Page: 326.19 Line No.: 10 Column: b

Settlement adjustment.

Schedule Page: 326.19 Line No.: 10 Column: l

Storage and exchange charges.

Schedule Page: 326.19 Line No.: 11 Column: b

Settlement adjustment.

Schedule Page: 326.19 Line No.: 11 Column: l

Storage and exchange charges.

Schedule Page: 326.19 Line No.: 12 Column: l

Storage and exchange charges.

Schedule Page: 326.19 Line No.: 13 Column: l

Storage and exchange charges.

Schedule Page: 326.19 Line No.: 14 Column: l

Storage and exchange charges.

Schedule Page: 326.20 Line No.: 2 Column: b

Settlement adjustment.

Schedule Page: 326.20 Line No.: 2 Column: l

Energy Imbalance Market ("EIM") entity settlements in EIM.

Schedule Page: 326.20 Line No.: 3 Column: b

Settlement adjustment.

Schedule Page: 326.20 Line No.: 3 Column: l

EIM participating resource settlements in EIM.

Schedule Page: 326.20 Line No.: 4 Column: l

EIM entity settlements in EIM.

Schedule Page: 326.20 Line No.: 5 Column: l

EIM participating resource settlements in EIM.

Schedule Page: 326.20 Line No.: 6 Column: l

Storage and exchange charges.

Schedule Page: 326.20 Line No.: 7 Column: l

Exchange energy expense.

Schedule Page: 326.20 Line No.: 9 Column: l
Station service for third-party wind project.

Schedule Page: 326.20 Line No.: 10 Column: l
Reimbursement for providing station service to third-party wind project.

Schedule Page: 326.20 Line No.: 11 Column: l
Reimbursement for providing station service to third-party wind project.

Schedule Page: 326.21 Line No.: 1 Column: l
Storage and exchange charges.

Schedule Page: 326.21 Line No.: 3 Column: l
Exchange energy expense.

Schedule Page: 326.21 Line No.: 5 Column: l
Imbalance energy.

Schedule Page: 326.21 Line No.: 6 Column: b
Settlement adjustment.

Schedule Page: 326.21 Line No.: 6 Column: l
Imbalance energy.

Schedule Page: 326.21 Line No.: 7 Column: l
Imbalance energy.

Schedule Page: 326.21 Line No.: 8 Column: l
Allocations of EIM charge codes to transmission customers.

Schedule Page: 326.21 Line No.: 9 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 2016/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	Avangrid Renewables, LLC			NF
3	Avangrid Renewables, LLC			AD
4	Avangrid Renewables, LLC			SFP
5	Avangrid Renewables, LLC			AD
6	Avangrid Renewables, LLC	Avangrid Renewables, LLC		OS
7	Avangrid Renewables, LLC	Avangrid Renewables, LLC		AD
8	Avangrid Renewables, LLC	Exxon Mobil	Nevada Power Company	LFP
9	Avangrid Renewables, LLC	Exxon Mobil	Nevada Power Company	AD
10	Avangrid Renewables, LLC	Bonneville Power Administration	Oregon Direct Access	FNO
11	Avangrid Renewables, LLC	Avangrid Renewables, LLC		AD
12	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corporation	FNO
13	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corporation	AD
14	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corporation	LFP
15	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corporation	NF
16	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corporation	AD
17	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corporation	SFP
18	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corporation	AD
19	Black Hills/Colorado Electric Utility Company			NF
20	Black Hills/Colorado Electric Utility Company			SFP
21	Black Hills Corporation	PacifiCorp	Montana-Dakota Utilities	FNO
22	Black Hills Corporation	PacifiCorp	Montana-Dakota Utilities	AD
23	Black Hills Corporation	PacifiCorp	Black Hills Corporation	LFP
24	Black Hills Corporation	PacifiCorp	Black Hills Corporation	AD
25	Black Hills Corporation			NF
26	Black Hills Corporation			SFP
27	Black Hills Power, Inc.			NF
28	Black Hills Power Marketing			AD
29	Black Hills Power, Inc.			SFP
30	Black Hills Power Marketing			AD
31	Bonneville Power Administration			OS
32	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS
33	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
34	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	LFP
	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 MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
R.S. 436		Borah/Brady Sub				1
V11-1-3,8	Various	Various		181,395	181,395	2
V11-1-3,8	Various	Various		21,234	21,234	3
V11-1-3,7	Various	Various		33,311	33,311	4
V11-1-3,7	Various	Various		8,937	8,937	5
V11-5,6						6
V11-5,6						7
V11-1,2,7	Trona Substation	Red Butte/Mona Sub	31	65,938	65,938	8
V11-1,2,7	Trona Substation	Red Butte/Mona Sub	31	8,190	8,190	9
V11-1-3,5,6	Ponderosa Substation	Various	14	124,645	124,645	10
V11-1-3,5,6	Ponderosa Substation	Various	12	8,639	8,639	11
V11-1,2,3	Yellowtail Sub	Sheridan Substation	10	68,871	68,871	12
V11-1,2,3	Yellowtail Sub	Sheridan Substation		360	360	13
V11-1,2,3	Dave Johnston Sub	Yellowtail Sub		85,100	85,100	14
V11-1,2,8	Various	Various		14,682	14,682	15
V11-1,2,8	Various	Various		213	213	16
V11-1,2,7	Various	Various		342	342	17
V11-1,2,7	Various	Various		15,561	15,561	18
V11-1,2,8	Various	Various		79	79	19
V11-1,2,7	Various	Various		75	75	20
V11-1,2	Various	Sheridan Substation	44			21
V11-1,2	Various	Sheridan Substation	45			22
V11-1,2,7	Various	Wyodak Substation	52	134,331	134,331	23
V11-1,2,7	Various	Wyodak Substation	52	3,764	3,764	24
V11-1,2,8	Various	Various		4,778	4,778	25
V11-1,2,7	Various	Various		159	159	26
V11-1,2,8	Various	Various		502	502	27
V11-1,2,8	Various	Various		82	82	28
V11-1,2,7	Various	Various		377	377	29
V11-1,2,7	Various	Various				30
R.S. 369	Midpoint Substation	Summer Lake Sub				31
R.S. 237	Various	Various	383	978,598	978,598	32
R.S. 237	Various	Various	382	93,545	93,545	33
V11-2,7	Lost Creek Hydro Plt	Alvey Substation	58	209,683	209,683	34
			4,773	**13,233,893**	**13,121,145**	

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
	1,529,697	201,310	1,731,007	2
		145,214	145,214	3
	429,720	56,835	486,555	4
		56,507	56,507	5
		236,946	236,946	6
		29,693	29,693	7
837,116		36,955	874,071	8
		87,738	87,738	9
260,183		129,266	389,449	10
		35,458	35,458	11
258,766		53,960	312,726	12
		1,679	1,679	13
669,693		96,203	765,896	14
	73,160	3,241	76,401	15
		1,775	1,775	16
	1,755	78	1,833	17
		62,101	62,101	18
	227	76	303	19
	172	-3	169	20
1,150,579		50,810	1,201,389	21
		124,070	124,070	22
1,391,699		61,593	1,453,292	23
		146,229	146,229	24
	10,490	473	10,963	25
	2,599	3,320	5,919	26
	1,790	64	1,854	27
		7,555	7,555	28
	786	3,753	4,539	29
		215	215	30
				31
4,072,175		67,947	4,140,122	32
		407,528	407,528	33
1,562,618		15,809	1,578,427	34
54,874,768	**7,682,503**	**38,096,280**	**100,653,551**	

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 2016/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	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
2	Bonneville Power Administration	Bonneville Power Administration	Umpqua Indian Utility Cooperative	FNO
3	Bonneville Power Administration	Bonneville Power Administration	Umpqua Indian Utility Cooperative	AD
4	Bonneville Power Administration	Bonneville Power Administration	Benton REA	FNO
5	Bonneville Power Administration	Bonneville Power Administration	Benton REA	AD
6	Bonneville Power Administration	Bonneville Power Administration	Umatilla Electric and Columbia	FNO
7	Bonneville Power Administration	Bonneville Power Administration	Umatilla Electric and Columbia	AD
8	Bonneville Power Administration	U. S. Bureau of Reclamation	Bonneville Power Administration	LFP
9	Bonneville Power Administration	U. S. Bureau of Reclamation	Bonneville Power Administration	AD
10	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS
11	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
12	Bonneville Power Administration	Bonneville Power Administration	Yakama Power	FNO
13	Bonneville Power Administration	Bonneville Power Administration	Yakama Power	AD
14	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS
15	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
16	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	FNO
17	Bonneville Power Administration			NF
18	Bonneville Power Administration			FNO
19	Bonneville Power Administration	Bonneville Power Administration	Clark Public Utilities	FNO
20	Bonneville Power Administration	Bonneville Power Administration	Clark Public Utilities	AD
21	Brookfield Energy Marketing LP			NF
22	Calpine Energy Solutions LLC	Bonneville Power Administration	Oregon Direct Access	FNO
23	Calpine Energy Solutions LLC	Bonneville Power Administration	Oregon Direct Access	AD
24	Cargill Power Markets, LLC			NF
25	Cargill Power Markets, LLC			AD
26	City of Anaheim			NF
27	City of Anaheim			SFP
28	Cowlitz County PUD	Cowlitz County PUD	Bonneville Power Administration	OS
29	Cowlitz County PUD	Cowlitz County PUD	Bonneville Power Administration	AD
30	Deseret Generation & Trans.	Deseret Generation & Trans.	Deseret Generation & Trans.	OS
31	Deseret Generation & Trans.	Deseret Generation & Trans.	Deseret Generation & Trans.	AD
32	Deseret Generation & Trans.			NF
33	Deseret Generation & Trans.			AD
34	Deseret Generation & Trans.			SFP
	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 2016/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.
V11-2,7	Lost Creek Hydro Plt	Alvey Substation	58	17,535	17,535	1
V11-1-3,5,6	Bonneville Power Adm	Gazley Substation	3	22,870	22,870	2
V11-1-3,5,6	Bonneville Power Adm	Gazley Substation	3	2,128	2,128	3
V11-1-3,5,6	Bonneville Power Adm	Tieton Substation	1	4,830	4,830	4
V11-1-3,5,6	Bonneville Power Adm	Tieton Substation	1	762	762	5
V11-1-3,5,6	McNary Substation	Hinkle Substation	1	873	873	6
V11-1-3,5,6	McNary Substation	Hinkle Substation	1	101	101	7
V11-2,7	USBR Green Springs	Bonneville Power Adm	19	49,850	49,850	8
V11-2,7	USBR Green Springs	Bonneville Power Adm	19			9
R.S. 368	Malin Substation	Malin Substation		618,238	618,238	10
R.S. 368	Malin Substation	Malin Substation		59,367	59,367	11
V11-1-3,5,6	Bonneville Power Adm		6	36,026	36,026	12
V11-1-3,5,6	Bonneville Power Adm		5	3,402	3,402	13
R.S. 299	Various	Various	68	456,782	456,782	14
R.S. 299	Various	Various	156	84,467	84,467	15
S.A. 746	Goshen	Various		515,326	515,326	16
V11-1,2,8	Various	Various		82	82	17
S.A. 747	Goshen	Various		175,926	175,926	18
V11-1-3,5,6	Cardwell-Merwin		18	101,470	101,470	19
V11-1-3,5,6	Cardwell-Merwin		25	14,424	14,424	20
V11-1,2,8	Various	Various		11,053	11,053	21
V11-1-3,5,6	Bonneville Power Adm	Various	22	159,520	159,520	22
V11-1-3,5,6	Bonneville Power Adm	Various	16	11,666	11,666	23
V11-1,2,8	Various	Various		19,764	19,764	24
V11-1,2,8	Various	Various		529	529	25
V11-1,2,8	Various	Various		46,155	46,155	26
V11-1,2,7	Various	Various		17	17	27
R.S. 234	Swift Unit No. 2	Woodland Substation				28
R.S. 234	Swift Unit No. 2	Woodland Substation				29
R.S. 280	Various	Various	91	599,812	599,812	30
R.S. 280	Various	Various	101	53,416	53,416	31
V11-1,2,8	Various	Various		16,105	16,105	32
V11-1,2,8	Various	Various		66	66	33
V11-1,2,7	Various	Various		213	213	34
			4,773	**13,233,893**	**13,121,145**	

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.
		161,215	161,215	1
86,963		161,970	248,933	2
		23,977	23,977	3
15,974		5,622	21,596	4
		4,951	4,951	5
2,536		1,048	3,584	6
		1,725	1,725	7
502,269		7,305	509,574	8
		50,662	50,662	9
		232,452	232,452	10
		2,687	2,687	11
153,122		133,467	286,589	12
		25,611	25,611	13
432,167		558,858	991,025	14
		168,726	168,726	15
2,139,486		534,772	2,674,258	16
	93,475	4,092	97,567	17
819,311		198,810	1,018,121	18
431,691		129,860	561,551	19
		84,011	84,011	20
	64,433	2,844	67,277	21
341,767		166,728	508,495	22
		43,773	43,773	23
	146,865	6,425	153,290	24
		3,576	3,576	25
	314,582	13,863	328,445	26
	166	7	173	27
		152,267	152,267	28
		13,795	13,795	29
2,413,640		1,756,625	4,170,265	30
		350,907	350,907	31
	100,802	4,447	105,249	32
		457	457	33
	756	34	790	34
54,874,768	**7,682,503**	**38,096,280**	**100,653,551**	

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 2016/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	Eugene Water & Electric Board			LFP
2	Eugene Water & Electric Board			AD
3	Eugene Water & Electric Board			SFP
4	Eugene Water & Electric Board			AD
5	Enel Cove Fort, LLC	Enel Cove Fort, LLC		AD
6	Exelon Generation Company, LLC	Bonneville Power Administration	Oregon Direct Access	FNO
7	Exelon Generation Company, LLC	Bonneville Power Administration	Oregon Direct Access	AD
8	Exelon Generation Company, LLC			NF
9	Exelon Generation Company, LLC			AD
10	Exelon Generation Company, LLC			SFP
11	Fall River Rural Electric Cooperative	Marysville Hydro Partners	Idaho Power Company	OS
12	Fall River Rural Electric Cooperative	Marysville Hydro Partners	Idaho Power Company	AD
13	Foote Creek III, LLC	Foote Creek III, LLC	PacifiCorp	OS
14	Foote Creek III, LLC	Foote Creek III, LLC	PacifiCorp	AD
15	Idaho Power Company			OS
16	Idaho Power Company			AD
17	Idaho Power Company			NF
18	Los Angeles Department of Water & Power			SFP
19	Macquarie Energy, LLC			NF
20	Moon Lake Electric Association	Moon Lake Electric Association	Moon Lake Electric Association	OS
21	Moon Lake Electric Association	Moon Lake Electric Association	Moon Lake Electric Association	AD
22	Morgan Stanley Capital Group, Inc.			NF
23	Morgan Stanley Capital Group, Inc.			AD
24	Morgan Stanley Capital Group, Inc.			SFP
25	Municipal Energy Nebraska, Inc.			NF
26	Nevada Power Company			NF
27	NextEra Energy Resources, LLC	NextEra Energy Resources, LLC	Grant County PUD	LFP
28	NextEra Energy Resources, LLC	NextEra Energy Resources, LLC	Grant County PUD	AD
29	NextEra Energy Resources, LLC			NF
30	NextEra Energy Resources, LLC			AD
31	NextEra Energy Resources, LLC			SFP
32	NextEra Energy Resources, LLC			AD
33	Olene KBG, LLC	Exxon Mobil	Nevada Power Company	LFP
34	Pacific Gas & Electric Company			OS
	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 2016/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.
V11-1,2,7	Various	Various				1
V11-1,2,7	Various	Various				2
V11-1,2,7	Various	Various				3
V11-1,2,7	Various	Various				4
V11-1-3,7	Enel Cove Fort	Red Butte Substation				5
V11-1-3,5,6	Bonneville Power Adm	Various	2	8,558	8,558	6
V11-1-3,5,6	Bonneville Power Adm	Various	2	1,682	1,682	7
V11-1-3,5,6,8	Various	Various		9,257	9,257	8
V11-1-3,5,6,8	Various	Various		118	118	9
V11-1-3,7	Various	Various				10
R.S. 322	Targhee Substation	Goshen Substation				11
R.S. 322	Targhee Substation	Goshen Substation				12
S.A. 761	Foote Creek Sub	Various				13
S.A. 761	Foote Creek Sub	Various				14
R.S. 257	Antelope Substation	Antelope Substation		7,006	7,006	15
S.A. 212	Trona Substation	Red Butte/Mona Sub				16
V11-1,2,8	Various	Various		17,699	17,699	17
V11-1,2,7	Various	Various		3,624	3,624	18
V11-1,2,8	Various	Various		74	74	19
R.S. 302	Duchesne	Duchesne		19,638	19,638	20
R.S. 302	Duchesne	Duchesne		1,984	1,984	21
V11-1-3,8	Various	Various		108,657	108,657	22
V11-1-3,8	Various	Various		13,701	13,701	23
V11-1-3,7	Various	Various		366	366	24
V11-1,2,8	Various	Various		156	156	25
V11-1,2,8	Various	Various		4,085	4,085	26
V11-1-3,5-7	Wallula Substation	Wala-MIDC path	103	163,687	163,687	27
V11-5-7	Wallula Substation	Wala-MIDC path	103	19,065	19,065	28
V11-1-3,8	Various	Various		5,563	5,563	29
V11-1,2,8	Various	Various		232	232	30
V11-1-3,7	Various	Various		368	368	31
V11-1,2,7	Various	Various		7	7	32
V11-1,2,7	PGE	Olene KBG, LLC				33
R.S. 607						34
			4,773	**13,233,893**	**13,121,145**	

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.
		595,577	595,577	1
		84,417	84,417	2
		202,479	202,479	3
		64,571	64,571	4
		-358	-358	5
28,577		12,552	41,129	6
		9,185	9,185	7
	170,166	63,777	233,943	8
		22,536	22,536	9
	1,018	62	1,080	10
		138,699	138,699	11
		12,609	12,609	12
		63,869	63,869	13
		8,024	8,024	14
969,535		42,848	1,012,383	15
		-15,133	-15,133	16
	98,751	4,357	103,108	17
	30,850	1,360	32,210	18
	358	16	374	19
		17,655	17,655	20
		1,605	1,605	21
	557,415	24,556	581,971	22
		79,237	79,237	23
	91,079	4,014	95,093	24
	2,463	108	2,571	25
	30,501	710	31,211	26
1,819,267		378,238	2,197,505	27
		259,107	259,107	28
	218,037	29,786	247,823	29
		24,252	24,252	30
	1,490	111	1,601	31
		25	25	32
748,841		33,028	781,869	33
		13,486,345	13,486,345	34
54,874,768	**7,682,503**	**38,096,280**	**100,653,551**	

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 2016/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			AD
2	Pacific Gas & Electric Company			NF
3	Pacific Gas & Electric Company			AD
4	PGE			NF
5	PGE			OS
6	Powder River Energy Corporation	Western Area Power Administration	Sheridan-Johnson Rural Elect.	OS
7	Powder River Energy Corporation	Western Area Power Administration	Sheridan-Johnson Rural Elect.	AD
8	Powerex Corporation	Bonneville Power Administration	CAISO	LFP
9	Powerex Corporation	Bonneville Power Administration	CAISO	AD
10	Powerex Corporation	Powerex Corporation	CAISO	LFP
11	Powerex Corporation	Powerex Corporation	CAISO	AD
12	Powerex Corporation	Powerex Corporation	CAISO	LFP
13	Powerex Corporation	Powerex Corporation	CAISO	AD
14	Powerex Corporation	Powerex Corporation	CAISO	LFP
15	Powerex Corporation	Powerex Corporation	CAISO	AD
16	Powerex Corporation	Powerex Corporation	CAISO	LFP
17	Powerex Corporation	Powerex Corporation	CAISO	AD
18	Powerex Corporation	Powerex Corporation	CAISO	LFP
19	Powerex Corporation	Powerex Corporation	CAISO	AD
20	Powerex Corporation			NF
21	Powerex Corporation			AD
22	Powerex Corporation			SFP
23	Powerex Corporation			AD
24	Puget Sound Power & Light Company			SFP
25	Rainbow Energy Marketing Corporation			NF
26	Sacramento Municipal Utility District	Sacramento Municipal Utility Dist	Sacramento Municipal Utility Dist	LFP
27	Sacramento Municipal Utility District	Sacramento Municipal Utility Dist	Sacramento Municipal Utility Dist	AD
28	Salt River Project	Salt River Project	Salt River Project	LFP
29	Salt River Project	Salt River Project	Salt River Project	AD
30	Shell Energy Corporation, Inc.	NextEra Energy Resources, LLC	Grant County PUD	LFP
31	Shell Energy Corporation, Inc.	NextEra Energy Resources, LLC	Grant County PUD	AD
32	Shell Energy Corporation, Inc.			NF
33	Shell Energy Corporation, Inc.			AD
34	Shell Energy Corporation, Inc.			SFP
	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 2016/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.
V11-1,2	Various	Various				1
V11-1,2,8	Various	Various		1,794	1,794	2
V11-1,2,8	Various	Various		594	594	3
V11-1,2,8	Various	Various		90	90	4
R.S. 137	Various	Various				5
R.S. 123	Various	Buffalo Substation				6
R.S. 123	Various	Buffalo Substation				7
V11-1,2,7	Bonneville Power Adm	CRAG View Substation	83	561,758	561,758	8
V11-1,2,7	Bonneville Power Adm	CRAG View Substation	83	29,486	29,486	9
V11-1,7	Malin 500 Substation	Round Mountain Sub	67			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	66			14
V11-1,7	Malin 500 Substation	Round Mountain Sub	66			15
V11-1,7	Malin 500 Substation	Round Mountain Sub	50			16
V11-1,7	Malin 500 Substation	Round Mountain Sub	50			17
V11-1,7	Malin 500 Substation	Round Mountain Sub	150			18
V11-1,7	Malin 500 Substation	Round Mountain Sub	50			19
V11-1,2,8	Various	Various		144,765	144,765	20
V11-1,2,8	Various	Various		14,192	14,192	21
V11-1-3,7	Various	Various		37,272	37,272	22
V11-1,2,7	Various	Various		330	330	23
V11-1,2,8	Various	Various				24
V11-1,2,8	Various	Various		5,026	5,026	25
V11-1,2,7	Malin Substation	Malin Substation	31	98,564	98,564	26
V11-1,2,7	Malin Substation	Malin Substation	31	16,272	16,272	27
V11-1,2,7	Enel Cove Fort	Red Butte Substation	26	152,353	152,353	28
V11-1,2,7	Enel Cove Fort	Red Butte Substation	26	15,221	15,221	29
V11-1,2,7	Wallula Substation	Wala-MIDC path		80,847	80,847	30
V11-1,2,7	Wallula Substation	Wala-MIDC path		11,216	11,216	31
V11-1-3,8	Various	Various		39,854	39,854	32
V11-1,2,8	Various	Various		2,388	2,388	33
V11-1-3,7	Various	Various		7,364	7,364	34
			4,773	**13,233,893**	**13,121,145**	

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.
		1,208,333	1,208,333	1
	11,263	1,039	12,302	2
		4,883	4,883	3
	643	28	671	4
		3,314	3,314	5
		373	373	6
		33	33	7
2,232,310		98,549	2,330,859	8
		231,671	231,671	9
1,789,909		45,240	1,835,149	10
		184,568	184,568	11
1,789,909		45,240	1,835,149	12
		184,568	184,568	13
1,763,193		44,564	1,807,757	14
		181,813	181,813	15
1,335,753		34,048	1,369,801	16
		171,853	171,853	17
4,007,259		102,143	4,109,402	18
		380,246	380,246	19
	892,202	75,746	967,948	20
		90,236	90,236	21
	192,933	32,339	225,272	22
		3,127	3,127	23
	15	1	16	24
	23,522	1,039	24,561	25
837,117		36,954	874,071	26
		87,738	87,738	27
697,610		30,798	728,408	28
		73,414	73,414	29
				30
				31
	231,898	10,640	242,538	32
		12,702	12,702	33
	29,900	1,383	31,283	34
54,874,768	**7,682,503**	**38,096,280**	**100,653,551**	

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 2016/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	Sierra Pacific Power Company			OS
2	Sierra Pacific Power Company			AD
3	Southern California Edison Company			NF
4	Southern California Edison Company			AD
5	Southern California Public Power Authority	Powerex Corporation	Southern California Public Power	NF
6	State of South Dakota	Western Area Power Administration	Black Hills Corporation	LFP
7	State of South Dakota	Western Area Power Administration	Black Hills Corporation	AD
8	Talen Energy Marketing, LLC			NF
9	Talen Energy Marketing, LLC			AD
10	Talen Energy Marketing, LLC			SFP
11	Tenaska Power Services Co			NF
12	Tenaska Power Services Co			AD
13	Tenaska Power Services Co			SFP
14	The Energy Authority, Inc.			NF
15	The Energy Authority, Inc.			SFP
16	Thermo No. 1 BE-01, LLC	Thermo Geothermal Project		LFP
17	Thermo No. 1 BE-01, LLC	Thermo Geothermal Project		AD
18	TransAlta Energy Marketing (U.S.) Inc.			NF
19	TransAlta Energy Marketing (U.S.) Inc.			AD
20	TransAlta Energy Marketing (U.S.) Inc.			SFP
21	Tri-State Generation & Trans.		Tri-State Generation & Trans.	FNO
22	Tri-State Generation & Trans.		Tri-State Generation & Trans.	AD
23	Tri-State Generation & Trans.			NF
24	U.S. Bureau of Reclamation	Bonneville Power Administration	U.S. Bureau of Reclamation	FNO
25	U.S. Bureau of Reclamation	Bonneville Power Administration	U.S. Bureau of Reclamation	AD
26	U.S. Bureau of Reclamation	Western Area Power Administration	Weber Basin Water Conserv.	OS
27	U.S. Bureau of Reclamation	Western Area Power Administration	Weber Basin Water Conserv.	AD
28	U.S. Bureau of Reclamation	Bonneville Power Administration	Crooked River Irrigation District	OS
29	Utah Associated Municipal Power Systems	Utah Associated Municipal Power	Utah Associated Municipal Power	OS
30	Utah Associated Municipal Power Systems	Utah Associated Municipal Power	Utah Associated Municipal Power	AD
31	Utah Associated Municipal Power Systems			NF
32	Utah Associated Municipal Power Systems			SFP
33	Utah Municipal Power Agency	Utah Municipal Power Agency	Utah Municipal Power Agency	OS
34	Utah Municipal Power Agency	Utah Municipal Power Agency	Utah Municipal Power Agency	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)	
R.S. 674	Sigurd Substation	Utah-Nevada Border				1
R.S. 674	Sigurd Substation	Utah-Nevada Border				2
V11-1-3,5,6,11	Various	Various		228,388	228,388	3
V11-1-3,5,6,11	Various	Various		1,681	1,681	4
V11-1-3,11	Tieton Substation	Various		53	53	5
V11-1,2,7	Yellowtail Sub	Wyodak Substation	4	17,599	17,599	6
V11-1,2,7	Yellowtail Sub	Wyodak Substation	4	1,681	1,681	7
V11-1,2,8	Various	Various		2,983	2,983	8
V11-1,2,8	Various	Various		20	20	9
V11-1,2,7	Various	Various		24	24	10
V11-1-3,8	Various	Various		5,214	5,214	11
V11-1-3,8	Various	Various		179	179	12
V11-1-3,7	Various	Various				13
V11-1,2,8	Various	Various		3,051	3,051	14
V11-1,2,7	Various	Various		50	50	15
V11-1-3,5-7	South Milford Sub	Mona Substation	11	56,872	56,872	16
V11-1-3,5-7	South Milford Sub	Mona Substation	11	6,244	6,244	17
V11-1,2,8	Various	Various		9,276	9,276	18
V11-1,2,8	Various	Various		1,995	1,995	19
V11-1,2,7	Various	Various		25	25	20
V11-1-3,5,6	Dave Johnston Sub	Thermopolis Sub	14	99,837	99,837	21
V11-1-4	Dave Johnston Sub	Thermopolis Sub	30	17,167	17,167	22
V11-1,2,8	Various	Various		3,553	3,553	23
V11-1-3,5,6	Walla Walla Sub	Burbank Pumps	1	2,414	2,414	24
V11-1-3,5,6	Walla Walla Sub	Burbank Pumps	1	3	3	25
R.S. 286	Various	Various		26,893	26,893	26
R.S. 286	Various	Various		810	810	27
R.S. 67	Redmond Substation	Crooked River Pumps		10,882	10,882	28
R.S. 297	Various	Various	498	2,901,867	2,901,867	29
R.S. 297	Various	Various	442	268,070	268,070	30
V11-1-3,8	Various	Various		21,109	21,109	31
V11-1-3,7	Various	Various		10,270	10,270	32
R.S. 637	Various	Various	96	579,724	579,724	33
R.S. 637	Various	Various	81	48,354	48,354	34
			4,773	**13,233,893**	**13,121,145**	

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.
		53,256	53,256	1
		6,265	6,265	2
	1,961,596	703,323	2,664,919	3
		332,642	332,642	4
		13,883	13,883	5
111,615		4,927	116,542	6
		11,714	11,714	7
	25,417	1,118	26,535	8
		71	71	9
	179	8	187	10
	27,671	1,220	28,891	11
		1,268	1,268	12
	2,860	417	3,277	13
	19,030	837	19,867	14
	178	8	186	15
306,956		85,083	392,039	16
		39,922	39,922	17
	51,089	2,252	53,341	18
		10,861	10,861	19
	170	8	178	20
361,583		124,757	486,340	21
		114,250	114,250	22
	29,454	1,295	30,749	23
9,066		14,006	23,072	24
		52	52	25
		26,894	26,894	26
		810	810	27
10,563			10,563	28
13,556,941		2,558,042	16,114,983	29
		1,364,058	1,364,058	30
	114,581	16,380	130,961	31
	37,245	5,435	42,680	32
2,586,597		410,503	2,997,100	33
		230,382	230,382	34
54,874,768	**7,682,503**	**38,096,280**	**100,653,551**	

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 2016/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	Warm Springs Power Enterprises	Warm Springs Power Enterprises	PGE	OS
2	Warm Springs Power Enterprises	Warm Springs Power Enterprises	PGE	AD
3	Westar Energy, Inc.			NF
4	Western Area Power Administration	Western Area Power Administration		OS
5	Western Area Power Administration	Western Area Power Administration		AD
6	Western Area Power Administration	Western Area Power Administration		OS
7	Western Area Power Administration	Western Area Power Administration		AD
8	Western Area Power Administration	Western Area Power Administration		OS
9	Western Area Power Administration	Western Area Power Administration	Western Area Power Administration	FNO
10	Western Area Power Administration	Western Area Power Adm CO River	Western Area Power Administration	AD
11	Western Area Power Adm CO River	Western Area Power Adm CO River		NF
12	Western Area Power Adm CO MO	Western Area Power Adm CO River		NF
13	Western Area Power Adm CO MO	Western Area Power Adm CO River		AD
14	Western Area Power Adm CO MO	Western Area Power Adm CO MO		SFP
15	Accrual			
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions 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.
R.S. 591	Pelton Reregulating	Round Butte Sub		74,899	74,899	1
R.S. 591	Pelton Reregulating	Round Butte Sub		7,578	7,578	2
V11-1,2,8	Various	Various				3
R.S. 262	Various	Various	330	1,672,625	1,572,269	4
R.S. 262	Various	Various	330	172,791	162,424	5
R.S. 263	Various	Various		44,634	41,960	6
R.S. 263	Various	Various		4,111	3,863	7
R.S. 684	Dave Johnston Sub	Various				8
V11-1,2	Wyoming Distribution	Wyoming Distribution	1	10,920	10,920	9
V11-1,2,8	Various	Wyoming Distribution	1	3	3	10
V11-1,2,8	Various	Various		291	291	11
V11-1,2,8	Various	Various		13,257	13,257	12
V11-1,2,8	Various	Various				13
V11-1,2,7	Various	Various		216	216	14
				155,201	156,098	15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			4,773	**13,233,893**	**13,121,145**	

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.
		109,725	109,725	1
		9,975	9,975	2
	7		7	3
2,339,411		550,000	2,889,411	4
		266,003	266,003	5
		40,266	40,266	6
		4,048	4,048	7
				8
31,001		35,471	66,472	9
		5,570	5,570	10
	2,846	125	2,971	11
	53,127	2,347	55,474	12
		7	7	13
	1,074	47	1,121	14
		4,775,935	4,775,935	15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
54,874,768	**7,682,503**	**38,096,280**	**100,653,551**	

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: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 2 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 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 Line No.: 2 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328 Line No.: 3 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 3 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 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 Line No.: 3 Column: m

2015 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER11-3646.

Schedule Page: 328 Line No.: 4 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 4 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

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. Generation regulation and frequency response service.

Schedule Page: 328 Line No.: 5 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 5 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 5 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 5 Column: m

2015 transmission and ancillary services.

Schedule Page: 328 Line No.: 6 Column: c

Avangrid Renewables, LLC and Utah Associated Municipal Power Systems

Schedule Page: 328 Line No.: 6 Column: d

Ancillary services under the Open Access Transmission Tariff (1st Revised Service Agreement 476) in effect until superseded.

Schedule Page: 328 Line No.: 6 Column: f
Long Hollow, WY Switching Station

Schedule Page: 328 Line No.: 6 Column: g
Long Hollow, WY Switching Station

Schedule Page: 328 Line No.: 6 Column: m
Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328 Line No.: 7 Column: c
Avangrid Renewables, LLC and Utah Associated Municipal Power Systems

Schedule Page: 328 Line No.: 7 Column: d
Ancillary services under the Open Access Transmission Tariff (1st Revised Service Agreement 476) in effect until superseded.

Schedule Page: 328 Line No.: 7 Column: f
Long Hollow, WY Switching Station

Schedule Page: 328 Line No.: 7 Column: g
Long Hollow, WY Switching Station

Schedule Page: 328 Line No.: 7 Column: m
2015 transmission and ancillary services. 2015 annual transmission services true-up refund.

Schedule Page: 328 Line No.: 8 Column: c
This footnote applies to all occurrences of "Nevada Power Company" on pages 328-330. 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: 328 Line No.: 8 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 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
Point-to-point transmission service under the Open Access Transmission Tariff (8th Revised Service Agreement 279) terminating on April 30, 2019.

Schedule Page: 328 Line No.: 9 Column: m
2015 transmission and ancillary services. 2015 annual transmission services true-up refund.

Schedule Page: 328 Line No.: 10 Column: d
Network transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 742) terminating no earlier than 12-months from notice by the customer.

Schedule Page: 328 Line No.: 10 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.: 11 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 11 Column: d
Network transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 742) terminating no earlier than 12-months from notice by the customer.

Schedule Page: 328 Line No.: 11 Column: m
2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

Schedule Page: 328 Line No.: 12 Column: d
Network transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 505) terminating no earlier than 12-months from notice by the customer.

Schedule Page: 328 Line No.: 12 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.: 13 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.: 13 Column: m

2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

Schedule Page: 328 Line No.: 14 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 818) terminating on December 31, 2016.

Schedule Page: 328 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 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: 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

2015 transmission and ancillary services.

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

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.: 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

2015 transmission and ancillary services.

Schedule Page: 328 Line No.: 19 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.: 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

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.: 20 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 20 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 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 Line No.: 20 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 21 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.: 21 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 22 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.: 22 Column: m
2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

Schedule Page: 328 Line No.: 23 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.: 23 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.: 24 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.: 24 Column: m
2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

Schedule Page: 328 Line No.: 25 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 25 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 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 Line No.: 25 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 26 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 26 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 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 Line No.: 26 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 27 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 27 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 27 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 27 Column: m

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.: 28 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 28 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 28 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 28 Column: m

2015 transmission and ancillary services.

Schedule Page: 328 Line No.: 29 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 29 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 29 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 29 Column: m

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.: 30 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 30 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 30 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 30 Column: m

2015 transmission and ancillary services.

Schedule Page: 328 Line No.: 31 Column: b

Capacity exchanged and operated by each transmission provider with no receipt or delivery of energy.

Schedule Page: 328 Line No.: 31 Column: c

Capacity exchanged and operated by each transmission provider with no receipt or delivery of energy.

Schedule Page: 328 Line No.: 31 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.: 32 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.: 32 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. 2013-2015 transmission demand adjustments.

Schedule Page: 328 Line No.: 33 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.: 33 Column: m

2015 transmission and ancillary services.

Schedule Page: 328 Line No.: 34 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (4th Revised Service Agreement 656) terminating on August 31, 2030.

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. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 1 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (4th Revised Service Agreement 656) terminating on August 31, 2030.

Schedule Page: 328.1 Line No.: 1 Column: m

2015 transmission and ancillary services. 2015 annual transmission services true-up refund.

Schedule Page: 328.1 Line No.: 2 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: 328.1 Line No.: 2 Column: f

This footnote applies to all occurrences of "Bonneville Power Adm" on pages 328-330. Complete name is Bonneville Power Administration.

Schedule Page: 328.1 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. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.1 Line No.: 3 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: 328.1 Line No.: 3 Column: m

2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

Schedule Page: 328.1 Line No.: 4 Column: c

This footnote applies to all occurrences of "Benton REA" on pages 328-330. Complete name is Benton Rural Electric Association.

Schedule Page: 328.1 Line No.: 4 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: 328.1 Line No.: 4 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.: 5 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: 328.1 Line No.: 5 Column: m
2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

Schedule Page: 328.1 Line No.: 6 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: 328.1 Line No.: 6 Column: d
Network transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 538) terminating on September 30, 2028.

Schedule Page: 328.1 Line No.: 6 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.: 7 Column: d
Network transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 538) terminating on September 30, 2028.

Schedule Page: 328.1 Line No.: 7 Column: m
2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

Schedule Page: 328.1 Line No.: 8 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: 328.1 Line No.: 8 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: 328.1 Line No.: 8 Column: m
Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 9 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: 328.1 Line No.: 9 Column: m
2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

Schedule Page: 328.1 Line No.: 10 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: 328.1 Line No.: 10 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.: 11 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: 328.1 Line No.: 11 Column: m
2015 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 12 Column: d
Network transmission service and distribution delivery service under the Open Access Transmission Tariff (7th Revised Service Agreement 328) terminating on September 30, 2028.

Schedule Page: 328.1 Line No.: 12 Column: g
White Swan/Toppenish Substations

Schedule Page: 328.1 Line No.: 12 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: 328.1 Line No.: 13 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.: 13 Column: g

White Swan/Toppenish Substations

Schedule Page: 328.1 Line No.: 13 Column: m

2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

Schedule Page: 328.1 Line No.: 14 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.: 14 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.: 15 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.: 15 Column: m

2015 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 16 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (2nd Revised Service Agreement 746) terminating on June 30, 2028.

Schedule Page: 328.1 Line No.: 16 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.: 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

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (1st Revised Service Agreement 747) terminating on June 30, 2028.

Schedule Page: 328.1 Line No.: 18 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.: 19 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.: 19 Column: g
Chelatchie/View 115kV

Schedule Page: 328.1 Line No.: 19 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.: 20 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.: 20 Column: g
Chelatchie/View 115kV

Schedule Page: 328.1 Line No.: 20 Column: m
2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

Schedule Page: 328.1 Line No.: 21 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 21 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 21 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 21 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 22 Column: d
Transmission service under the Open Access Transmission Tariff (10th Revised Service Agreement 299). Service provided pursuant to rules and regulations of Oregon Direct Access. Agreement terminates upon notification pursuant to Oregon Direct Access and Open Access Transmission Tariff.

Schedule Page: 328.1 Line No.: 22 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.: 23 Column: d
Transmission service under the Open Access Transmission Tariff (10th Revised Service Agreement 299). Service provided pursuant to rules and regulations of Oregon Direct Access. Agreement terminates upon notification pursuant to Oregon Direct Access and Open Access Transmission Tariff.

Schedule Page: 328.1 Line No.: 23 Column: m
2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

Schedule Page: 328.1 Line No.: 24 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 24 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 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: 328.1 Line No.: 24 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 25 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 25 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 25 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 25 Column: m

2015 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 26 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 26 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 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: 328.1 Line No.: 26 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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: 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.: 28 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.: 28 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.: 29 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.: 29 Column: m

2015 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 30 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.: 30 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.: 30 Column: m

Distribution voltage service charge. Meter interrogation services. 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.: 31 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.: 31 Column: m

2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

Schedule Page: 328.1 Line No.: 32 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 32 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 32 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 32 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 33 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 33 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 33 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 33 Column: m

2015 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 34 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 34 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 34 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 34 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 1 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 1 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 1 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 780) terminating no earlier than 12-months from notice by the customer.

Schedule Page: 328.2 Line No.: 1 Column: m

Transmission resale - purchase of point-to-point transmission. Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 2 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

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
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.: 2 Column: m
2015 transmission and ancillary services. 2015 annual transmission services true-up refund.

Schedule Page: 328.2 Line No.: 3 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 3 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 3 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 3 Column: m
Transmission resale - purchase of point-to-point transmission. Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 4 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 4 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 4 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 4 Column: m
2015 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 5 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 5 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: 328.2 Line No.: 5 Column: m
2015 transmission and ancillary services. 2015 annual transmission services true-up refund.

Schedule Page: 328.2 Line No.: 6 Column: d
Transmission service under the Open Access Transmission Tariff (1st Revised Service Agreement 789). Service provided pursuant to rules and regulations of Oregon Direct Access terminating on December 31, 2016.

Schedule Page: 328.2 Line No.: 6 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.: 7 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: 328.2 Line No.: 7 Column: m
2015 transmission and ancillary services. 2015 annual transmission services true-up refund.

Schedule Page: 328.2 Line No.: 8 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 8 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 8 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 8 Column: m
Reactive supply and voltage control service. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service. Unauthorized use of transmission service. Scheduling, system control and dispatch service.

Schedule Page: 328.2 Line No.: 9 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 9 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 9 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 9 Column: m
2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

Schedule Page: 328.2 Line No.: 10 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 10 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 10 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 10 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.2 Line No.: 11 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: 328.2 Line No.: 11 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.: 12 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: 328.2 Line No.: 12 Column: m
2015 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 13 Column: d
Service Agreement 761 executed between PacifiCorp and Foote Creek III, LLC (d/b/a 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: 328.2 Line No.: 13 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: 328.2 Line No.: 14 Column: d
Service Agreement 761 executed between PacifiCorp and Foote Creek III, LLC (d/b/a 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: 328.2 Line No.: 14 Column: m
2015 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 15 Column: b
Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 15 Column: c
Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 15 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 Power Company and United States Department of Education Supply Agreement.

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
Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 16 Column: c
Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 16 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.: 16 Column: m
2015 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER11-3646.

Schedule Page: 328.2 Line No.: 17 Column: b
Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 17 Column: c
Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 17 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 17 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 18 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 18 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 18 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 18 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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.

Schedule Page: 328.2 Line No.: 20 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.: 20 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.: 21 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.: 21 Column: m

2015 transmission and ancillary services.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

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

2015 transmission and ancillary services.

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. Generation regulation and frequency response 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: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 26 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 26 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 26 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 27 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.: 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

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.: 28 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.: 28 Column: m

2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

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

2015 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER11-3646.

Schedule Page: 328.2 Line No.: 31 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 31 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 31 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 31 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.: 32 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 32 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 32 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 32 Column: m
2015 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 33 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 766) terminating on May 31, 2019.

Schedule Page: 328.2 Line No.: 33 Column: f
This footnote applies to all occurrences of "PGE" on pages 328-330. Complete name is Portland General Electric Company.

Schedule Page: 328.2 Line No.: 33 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 34 Column: b
Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 34 Column: c
Operation, maintenance or facility lease services with no receipt or delivery of energy.

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: f
Malin to Indian Springs line segment

Schedule Page: 328.2 Line No.: 34 Column: g
Malin to Indian Springs line segment

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.

Schedule Page: 328.3 Line No.: 1 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 1 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 1 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 on December 31, 2017. See PacifiCorp, Docket No. ER07-882, et al, Settlement Agreement, Appendix 2 (filed November 20, 2007).

Schedule Page: 328.3 Line No.: 1 Column: m
2015 transmission and ancillary services.

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. Generation regulation and frequency response 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
2015 transmission and ancillary services.

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
Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 5 Column: c
Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 5 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 on December 2013.

Schedule Page: 328.3 Line No.: 5 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.: 6 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.: 6 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.: 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: 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
2015 transmission and ancillary services.

Schedule Page: 328.3 Line No.: 8 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.: 8 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.: 8 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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

2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

Schedule Page: 328.3 Line No.: 10 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.: 10 Column: m

Scheduling, system control and dispatch service.

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

2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

Schedule Page: 328.3 Line No.: 12 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.: 12 Column: m

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

2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

Schedule Page: 328.3 Line No.: 14 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.: 14 Column: m

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

2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

Schedule Page: 328.3 Line No.: 16 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.: 16 Column: m

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

2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

Schedule Page: 328.3 Line No.: 18 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.: 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

2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

Schedule Page: 328.3 Line No.: 20 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 20 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 20 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 20 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control 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

2015 transmission and ancillary services.

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

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.: 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

2015 transmission and ancillary services.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 26 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.: 26 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 751) terminating on September 30, 2018.

Schedule Page: 328.3 Line No.: 26 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 27 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 751) terminating on September 30, 2018.

Schedule Page: 328.3 Line No.: 27 Column: m

2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

Schedule Page: 328.3 Line No.: 28 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.: 28 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 29 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.: 29 Column: m

2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

Schedule Page: 328.3 Line No.: 30 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (9th Revised Service Agreement 791) terminating upon written notification.

Schedule Page: 328.3 Line No.: 31 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (9th Revised Service Agreement 791) terminating upon written notification.

Schedule Page: 328.3 Line No.: 32 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 32 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 32 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.: 33 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 33 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 33 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 33 Column: m

2015 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. Generation regulation and frequency response service.

Schedule Page: 328.4 Line No.: 1 Column: a

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: 328.4 Line No.: 1 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 1 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 1 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.: 1 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.: 2 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 2 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 2 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.: 2 Column: m

2015 transmission and ancillary services.

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.: 3 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.: 4 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 4 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 4 Column: m

2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

Schedule Page: 328.4 Line No.: 5 Column: c

Complete name is Southern California Public Power Authority. Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 5 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.: 5 Column: m

Unauthorized use of transmission service.

Schedule Page: 328.4 Line No.: 6 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.: 6 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 7 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.: 7 Column: m

2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 9 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 9 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 9 Column: m

2015 transmission and ancillary services.

Schedule Page: 328.4 Line No.: 10 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 10 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 10 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 11 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 11 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 11 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.: 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: m
2015 transmission and ancillary services.

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: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service.

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.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 16 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 16 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.: 16 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.: 17 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 17 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.: 17 Column: m

2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

Schedule Page: 328.4 Line No.: 18 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 18 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 18 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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

2015 transmission and ancillary services.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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: d

Network transmission service under the Open Access Transmission Tariff (7th Revised

Service Agreement 628) terminating on June 30, 2021.

Schedule Page: 328.4 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: 328.4 Line No.: 22 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.: 22 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 22 Column: d

Network transmission service under the Open Access Transmission Tariff (7th Revised Service Agreement 628) terminating on June 30, 2021.

Schedule Page: 328.4 Line No.: 22 Column: m

2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

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.

Schedule Page: 328.4 Line No.: 24 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (2nd Revised Service Agreement 506) terminating upon written notification.

Schedule Page: 328.4 Line No.: 24 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: 328.4 Line No.: 25 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (2nd Revised Service Agreement 506) terminating upon written notification.

Schedule Page: 328.4 Line No.: 25 Column: m

2015 transmission and ancillary services. 2015 annual transmission services true-up refund.

Schedule Page: 328.4 Line No.: 26 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: 328.4 Line No.: 26 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: 328.4 Line No.: 26 Column: m

Energy consumption charge for deliveries at and below 138kV.

Schedule Page: 328.4 Line No.: 27 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: 328.4 Line No.: 27 Column: m

2015 transmission and ancillary services.

Schedule Page: 328.4 Line No.: 28 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: 328.4 Line No.: 29 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: 328.4 Line No.: 29 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, 4th Revised Rate Schedule 297). Agreement subject to termination upon mutual agreement and replacement agreements are in effect.

Schedule Page: 328.4 Line No.: 29 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: 328.4 Line No.: 30 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: 328.4 Line No.: 30 Column: m

2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

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. Generation regulation and frequency response 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

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.4 Line No.: 33 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: 328.4 Line No.: 33 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: 328.4 Line No.: 34 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: 328.4 Line No.: 34 Column: m

2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

Schedule Page: 328.5 Line No.: 1 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.: 1 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.: 2 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.: 2 Column: m

2015 transmission and ancillary services.

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.: 4 Column: c

Various Western Area Power Administration customers in PacifiCorp's control area.

Schedule Page: 328.5 Line No.: 4 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.: 4 Column: m

Fixed termination fee associated with a contract cancellation applied for the duration of this agreement.

Schedule Page: 328.5 Line No.: 5 Column: c

Various Western Area Power Administration customers in PacifiCorp's control area.

Schedule Page: 328.5 Line No.: 5 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.: 5 Column: m

2015 transmission and ancillary services.

Schedule Page: 328.5 Line No.: 6 Column: c

Various Western Area Power Administration customers in PacifiCorp's control area.

Schedule Page: 328.5 Line No.: 6 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.: 6 Column: m

Charges for low-voltage transmission of power and energy.

Schedule Page: 328.5 Line No.: 7 Column: c

Various Western Area Power Administration customers in PacifiCorp's control area.

Schedule Page: 328.5 Line No.: 7 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.: 7 Column: m

2015 transmission and ancillary services.

Schedule Page: 328.5 Line No.: 8 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 8 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.: 9 Column: d

Evergreen network transmission service under the Open Access Transmission Tariff (4th Revised Service Agreement 175).

Schedule Page: 328.5 Line No.: 9 Column: m

Distribution voltage service charge. Primary delivery service. Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 10 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.: 10 Column: d

Evergreen network transmission service under the Open Access Transmission Tariff (4th Revised Service Agreement 175).

Schedule Page: 328.5 Line No.: 10 Column: m

2015 transmission and ancillary services. 2012 annual transmission services true-up charge. 2015 annual transmission services true-up refund.

Schedule Page: 328.5 Line No.: 11 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 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: 328.5 Line No.: 11 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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.

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

2015 transmission and ancillary services.

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.

Schedule Page: 328.5 Line No.: 15 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 2016/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Arizona Public Service	AD			-1,602			-1,602
2	Arizona Public Service	LFP	479,252	479,252	1,835,595			1,835,595
3	Arizona Public Service	NF	18,165	18,165	34,142			34,142
4	Arizona Public Service	OS					14,099	14,099
5	Arizona Public Service	SFP	53,915	53,915	341,441			341,441
6	Ashland, City of	FNS	2,531	2,531		23,573		23,573
7	Avista Corporation	FNS	982,566	984,354	217,930			217,930
8	Avista Corporation	NF	8,153	8,153	47,043			47,043
9	Big Horn Rural Electric	OLF					161,364	161,364
10	Black Hills Power, Inc.	NF	18,021	18,021	17,333			17,333
11	Black Hills Power, Inc.	OS					21,340	21,340
12	Black Hills Power, Inc.	SFP	2,788	2,788	17,924			17,924
13	Bonneville Power Admin	AD	-401	-401	-847	123	-96	-820
14	Bonneville Power Admin	FNS			6,700,449			6,700,449
15	Bonneville Power Admin	LFP	5,274,941	5,274,941	67,216,014			67,216,014
16	Bonneville Power Admin	NF	96,955	96,955		500,176		500,176
	TOTAL		17,233,688	17,651,786	125,377,132	2,366,941	3,044,834	130,788,907

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 2016/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	OLF	3,690,451	3,951,094	22,054,278		97,364	22,151,642
2	Bonneville Power Admin	OS	53,628	53,628		24,124	64,730	88,854
3	Bonneville Power Admin	SFP	352,629	352,629		1,808,440		1,808,440
4	CA Ind Sys Operator	AD				-4,055	340,750	336,695
5	CA Ind Sys Operator	OS	2,115	2,115			1,769,502	1,769,502
6	CA Ind Sys Operator	SFP				22,972		22,972
7	Deseret Gen & Trans	LFP	125,602	125,602	4,480,063			4,480,063
8	Deseret Gen & Trans	NF	1,510	1,510	11,069			11,069
9	El Paso Electric Co.	OS					2,875	2,875
10	El Paso Electric Co.	SFP	18,438	18,438	16,077			16,077
11	Flathead Elect Coop Inc	OS					87,049	87,049
12	Hermiston Gen Co L.P.	OS					194,404	194,404
13	Idaho Power Company	AD					146,141	146,141
14	Idaho Power Company	FNS			10,789			10,789
15	Idaho Power Company	LFP	4,395,980	4,480,350	12,215,826			12,215,826
16	Idaho Power Company	NF	165,198	165,198	525,010			525,010
	TOTAL		17,233,688	17,651,786	125,377,132	2,366,941	3,044,834	130,788,907

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 2016/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	Idaho Power Company	OS				-9,787	2,896	-6,891
2	Idaho Power Company	SFP	253,520	253,520	670,059			670,059
3	Moon Lake Elect. Assoc.	FNS					285,018	285,018
4	Morgan City Corporation	LFP	11	11		1,375		1,375
5	Nevada Power Company	AD			7,500		-12,863	-5,363
6	Nevada Power Company	NF	3,843	3,843	21,154			21,154
7	Nevada Power Company	OS					136,649	136,649
8	Nevada Power Company	SFP	245,140	245,140	1,007,300			1,007,300
9	NorthWestern Corp.	NF	14,451	16,144	169,672			169,672
10	NorthWestern Corp.	OS					11,817	11,817
11	NorthWestern Corp.	SFP	16,038	16,038	69,509			69,509
12	Platte River Pwr Auth	LFP	172,581	172,581	849,700			849,700
13	Platte River Pwr Auth	OS					17,437	17,437
14	Portland Gen. Electric	OLF					921	921
15	Portland Gen. Electric	OS	-62,388					
16	Powerex Corporation	SFP			-627,754			-627,754
	TOTAL		17,233,688	17,651,786	125,377,132	2,366,941	3,044,834	130,788,907

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 2016/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	Public Service Co of CO	LFP	75,103	78,703	1,040,781			1,040,781
2	Public Service Co of CO	NF			-7			-7
3	Public Service Co of NM	AD			3,447			3,447
4	Public Service Co of NM	NF	240	240	1,432			1,432
5	Public Service Co of NM	OS					100	100
6	Puget Sound Energy, Inc	AD	4,150	4,150	4,950			4,950
7	Puget Sound Energy, Inc	SFP	254,478	254,478	314,189			314,189
8	Salt River Project	NF	5,880	5,880	14,944			14,944
9	Salt River Project	OS					1,898	1,898
10	Seattle City Light	SFP	1,200	1,200	3,000			3,000
11	Sierra Pacific Power Co	NF	7,070	7,070	44,188			44,188
12	Sierra Pacific Power Co	OS					5,939	5,939
13	Surprise Valley Electr.	OLF					7,623	7,623
14	The Energy Authority	SFP			-7,640			-7,640
15	TransAlta Energy	SFP			-19,652			-19,652
16	Tri-State Gen & Transm	LFP	64,400	68,016	1,040,781			1,040,781
	TOTAL		17,233,688	17,651,786	125,377,132	2,366,941	3,044,834	130,788,907

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 2016/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Tri-State Gen & Transm	NF	6,051	6,051	26,783			26,783
2	Tri-State Gen & Transm	OS					13,844	13,844
3	Tucson Electric Power	NF	2,135	2,135	9,666			9,666
4	Tucson Electric Power	OS					1,193	1,193
5	Tucson Electric Power	SFP	600	600	2,600			2,600
6	Western Area Power Admn	AD			12,191		-18,115	-5,924
7	Western Area Power Admn	FNS			6,226,792			6,226,792
8	Western Area Power Admn	LFP	317,177	317,177	2,016,250			2,016,250
9	Western Area Power Admn	NF	74,587	74,587	141,342			141,342
10	Western Area Power Admn	OS					770,951	770,951
11	Western Area Power Admn	SFP	34,984	34,984	87,348			87,348
12	Westport Field Svc LLC	LFP			-3,491,927			-3,491,927
13	Reserve						528,800	528,800
14	Accrual						-1,608,796	-1,608,796
15								
16								
	TOTAL		17,233,688	17,651,786	125,377,132	2,366,941	3,044,834	130,788,907

Schedule Page: 332 Line No.: 1 Column: b
Settlement adjustment.

Schedule Page: 332 Line No.: 1 Column: e
Settlement adjustment.

Schedule Page: 332 Line No.: 2 Column: b
Arizona Public Service Company - contract termination dates: January 11, 2041 and the date that all generating plants comprising PacifiCorp resources associated with this agreement have been retired from service or interests transferred.

Schedule Page: 332 Line No.: 4 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.: 4 Column: g
Ancillary services.

Schedule Page: 332 Line No.: 9 Column: b
Big Horn Rural Electric Company - contract termination date: March 10, 2018.

Schedule Page: 332 Line No.: 9 Column: g
Use of facilities.

Schedule Page: 332 Line No.: 11 Column: g
Ancillary services.

Schedule Page: 332 Line No.: 13 Column: b
Settlement adjustment.

Schedule Page: 332 Line No.: 13 Column: e
Settlement adjustment.

Schedule Page: 332 Line No.: 13 Column: g
Settlement adjustment.

Schedule Page: 332 Line No.: 15 Column: b
Bonneville Power Administration - contract termination dates: 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.: 1 Column: b
Bonneville Power Administration - contract termination dates: December 31, 2018; September 30, 2027 and evergreen.

Schedule Page: 332.1 Line No.: 1 Column: g
Use of facilities.

Schedule Page: 332.1 Line No.: 2 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.: 2 Column: g
Ancillary services. Use of facilities.

Schedule Page: 332.1 Line No.: 4 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.: 4 Column: b
Settlement adjustment.

Schedule Page: 332.1 Line No.: 4 Column: f

Settlement adjustment.

Schedule Page: 332.1 Line No.: 4 Column: g

Settlement adjustment.

Schedule Page: 332.1 Line No.: 5 Column: g

Ancillary services. Use of facilities.

Schedule Page: 332.1 Line No.: 7 Column: b

Deseret Generation and Transmission Co-operative - contract termination dates: January 1, 2018 and September 1, 2018.

Schedule Page: 332.1 Line No.: 9 Column: g

Ancillary services.

Schedule Page: 332.1 Line No.: 11 Column: g

Use of facilities.

Schedule Page: 332.1 Line No.: 12 Column: a

Hermiston Generating Company, L.P. operates the Hermiston Generating Plant, which is jointly owned. PacifiCorp owns 50% of the plant.

Schedule Page: 332.1 Line No.: 12 Column: g

Use of facilities.

Schedule Page: 332.1 Line No.: 13 Column: b

Settlement adjustment.

Schedule Page: 332.1 Line No.: 13 Column: g

Settlement adjustment.

Schedule Page: 332.1 Line No.: 15 Column: b

Idaho Power Company - contract termination dates: April 1, 2025 and July 1, 2025.

Schedule Page: 332.2 Line No.: 1 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.: 1 Column: f

Settlement adjustment.

Schedule Page: 332.2 Line No.: 1 Column: g

Ancillary services. Use of facilities. PacifiCorp's portion of specified costs of certain facilities.

Schedule Page: 332.2 Line No.: 3 Column: g

Use of facilities.

Schedule Page: 332.2 Line No.: 4 Column: b

Morgan City Corporation - contract termination date: Evergreen.

Schedule Page: 332.2 Line No.: 5 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.: 5 Column: b

Settlement adjustment.

Schedule Page: 332.2 Line No.: 5 Column: g

Settlement adjustment.

Schedule Page: 332.2 Line No.: 7 Column: g

Ancillary services.

Schedule Page: 332.2 Line No.: 10 Column: g

Ancillary services.

Schedule Page: 332.2 Line No.: 12 Column: b

Platte River Power Authority - contract termination date: October 31, 2017.

Schedule Page: 332.2 Line No.: 13 Column: g

Ancillary services.

Schedule Page: 332.2 Line No.: 14 Column: b

Portland General Electric Company - contract termination date: Upon two years written notice.

Schedule Page: 332.2 Line No.: 14 Column: g

Use of facilities.

Schedule Page: 332.2 Line No.: 16 Column: e

Reassignment of Bonneville Power Administration transmission.

Schedule Page: 332.3 Line No.: 1 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.: 2 Column: e

Settlement adjustment.

Schedule Page: 332.3 Line No.: 3 Column: b

Settlement adjustment.

Schedule Page: 332.3 Line No.: 5 Column: g

Ancillary services.

Schedule Page: 332.3 Line No.: 6 Column: b

Settlement adjustment.

Schedule Page: 332.3 Line No.: 9 Column: g

Ancillary services.

Schedule Page: 332.3 Line No.: 11 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: 332.3 Line No.: 12 Column: g

Ancillary services.

Schedule Page: 332.3 Line No.: 13 Column: b

Surprise Valley Electrification Corp. - contract termination date: Evergreen.

Schedule Page: 332.3 Line No.: 13 Column: g

Settlement adjustment.

Schedule Page: 332.3 Line No.: 14 Column: e

Reassignment of Bonneville Power Administration transmission.

Schedule Page: 332.3 Line No.: 15 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: 332.3 Line No.: 15 Column: e

Reassignment of Bonneville Power Administration transmission.

Schedule Page: 332.3 Line No.: 16 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.: 2 Column: g

Settlement adjustment.

Schedule Page: 332.4 Line No.: 4 Column: g

Ancillary services.

Schedule Page: 332.4 Line No.: 6 Column: b

Settlement adjustment.

Schedule Page: 332.4 Line No.: 6 Column: g

Settlement adjustment.

Schedule Page: 332.4 Line No.: 8 Column: b

Western Area Power Administration - contract termination date: May 31, 2022.

Schedule Page: 332.4 Line No.: 10 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: 332.4 Line No.: 10 Column: g

Ancillary services. Use of facilities.

Schedule Page: 332.4 Line No.: 12 Column: b

Westport Field Services, LLC - contract termination date: Evergreen.

Schedule Page: 332.4 Line No.: 12 Column: e

Reimbursement for third party services.

Schedule Page: 332.4 Line No.: 13 Column: g

Reserve for a contingent liability.

Schedule Page: 332.4 Line No.: 14 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 (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,148,762
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	American Wind Energy Association	10,000
10	Associated Oregon Industries	28,840
11	Clatsop Economic Development Resources	6,000
12	Economic Development for Central Oregon	7,500
13	Greater Yakima Chamber of Commerce	5,000
14	Hollywood Theatre	5,000
15	Independent Energy Producers Association, Inc.	21,875
16	Intermountain Electrical Association	9,000
17	Klamath County Economic Development Association	7,500
18	Laramie Chamber of Business Alliance	5,000
19	National Safety Council	6,035
20	Ogden-Weber Chamber of Commerce	6,000
21	Oregon Business Association	14,595
22	Oregon Business Council	17,953
23	Oregon Economic Development Association	7,500
24	Oregon Sports Authority	5,000
25	Oregon State University Utility Pole Research Coop	15,000
26	Pacific Northwest Utilities Conference Committee	78,674
27	Redmond Economic Development, Inc.	7,000
28	Rocky Mountain Electrical League	18,000
29	Rural Development Initiatives, Inc.	5,000
30	Salt Lake Area Chamber of Commerce	28,350
31	South Coast Development Council, Inc.	5,500
32	Strategic Economic Development Corporation	6,400
33	University of Utah	25,000
34	Utah Taxpayers Association	18,700
35	Utah Technology Council	12,000
36	Yakima County Development Association	7,500
37	Other (Individually < $5,000)	153,302
38		
39	Directors' Fees - Regional Advisory Board	14,534
40		
41	Rating Agency and Trustee Fees:	
42	The Bank of New York Mellon	129,848
43	Computershare Shareowner Services, LLC	17,172
44	CUSIP Global Services	595
45	Fitch, Inc.	39,323
46	TOTAL	2,346,536

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 2016/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
6	Moody's Investor Services, Inc.	96,525
7	Standard and Poor's Financial Services, LLC	260,038
8	U.S. Bancorp	10,944
9		
10	Regulatory Asset Amortization:	
11	Generating Plant Liquidated Damages - UT	35,000
12	Generating Plan Liquidated Damages - WY	54,288
13		
14	General:	
15	Other	-3,717
16		
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46	TOTAL	2,346,536

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 2016/Q4

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

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			36,791,866		36,791,866
2	Steam Production Plant	259,494,969				259,494,969
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	34,101,659		304,546		34,406,205
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	126,906,136				126,906,136
7	Transmission Plant	104,655,006				104,655,006
8	Distribution Plant	144,013,757				144,013,757
9	Regional Transmission and Market Operation					
10	General Plant	39,923,447		1,480,588		41,404,035
11	Common Plant-Electric					
12	TOTAL	709,094,974		38,577,000		747,671,974

B. Basis for Amortization Charges

The Amortization of Limited-Term Electric Plant is based on straight-line amortization over the life of the asset.

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	STEAM PRODUCTION						
13	Blundell Plant						
14	310.20 UT	40,982	46.97		2.09		24.00
15	311.00 UT	8,296	42.30	-4.00	2.51		23.30
16	312.00 UT	57,519	34.11	-3.00	2.98		22.20
17	314.00 UT	34,086	32.76	-5.00	3.30		21.50
18	315.00 UT	8,575	39.15	-3.00	2.70		23.10
19	316.00 UT	1,386	29.19	-5.00	3.76		19.30
20	Cholla Plant						
21	310.20 AZ	1,368	34.48		2.89		29.00
22	311.00 AZ	65,183	45.93	-6.00	2.34		28.00
23	312.00 AZ	339,497	37.41	-5.00	2.89		26.20
24	314.00 AZ	67,634	38.37	-7.00	2.85		24.80
25	315.00 AZ	68,727	46.05	-5.00	2.32		27.30
26	316.00 AZ	4,094	33.53	-7.00	3.31		21.40
27	Colstrip Plant						
28	311.00 MT	61,428	55.79	-6.00	1.88		31.50
29	312.00 MT	119,477	47.52	-6.00	2.24		28.10
30	314.00 MT	38,426	41.60	-8.00	2.61		27.30
31	315.00 MT	9,224	56.37	-5.00	1.83		30.00
32	316.00 MT	397	36.94	-7.00	2.90		22.90
33	Craig Plant						
34	311.00 CO	38,324	48.45	-6.00	2.11		20.40
35	312.00 CO	96,437	34.51	-5.00	3.00		19.40
36	314.00 CO	28,715	31.03	-7.00	3.50		19.10
37	315.00 CO	17,066	49.53	-5.00	2.04		19.80
38	316.00 CO	1,240	34.18	-7.00	3.11		16.50
39	Dave Johnston Plant						
40	310.20 WY	100	53.86		2.30		14.00
41	311.00 WY	158,156	20.39	-4.00	5.56		13.80
42	312.00 WY	689,845	19.99	-4.00	5.69		13.60
43	314.00 WY	96,287	24.19	-5.00	4.82		13.20
44	315.00 WY	62,765	20.04	-3.00	5.67		13.80
45	316.00 WY	8,418	18.11	-4.00	6.03		12.60
46	Gadsby Plant						
47	311.00 UT	15,108	43.40	-15.00	2.02		18.60
48	312.00 UT	38,900	39.12	-13.00	2.22		17.50
49	314.00 UT	19,917	37.19	-15.00	2.43		16.80
50	315.00 UT	8,420	34.93	-14.00	2.87		18.30

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	316.00 UT	458	29.04	-13.00	3.17		15.80
13	Hayden Plant						
14	311.00 CO	17,688	23.54	-5.00	4.62		16.70
15	312.00 CO	82,794	30.98	-5.00	3.14		16.00
16	314.00 CO	9,633	27.79	-6.00	3.69		15.80
17	315.00 CO	2,555	48.38	-5.00	1.74		16.10
18	316.00 CO	637	30.28	-6.00	3.22		14.20
19	Hunter Plant						
20	310.20 UT	246	60.93		1.61		29.00
21	311.00 UT	209,648	55.00	-7.00	1.93		27.80
22	312.00 UT	758,565	38.55	-6.00	2.79		26.10
23	314.00 UT	200,440	34.57	-8.00	3.17		25.60
24	315.00 UT	107,848	53.28	-6.00	1.97		26.70
25	316.00 UT	3,691	35.58	-8.00	3.08		20.80
26	Huntington Plant						
27	311.00 UT	124,429	45.56	-7.00	2.39		22.30
28	312.00 UT	563,304	29.78	-6.00	3.64		21.60
29	314.00 UT	123,318	31.75	-7.00	3.43		20.80
30	315.00 UT	47,559	39.00	-6.00	2.78		22.00
31	316.00 UT	2,890	27.99	-7.00	3.96		18.70
32	Jim Bridger Plant						
33	310.20 WY	281	61.28		1.36		24.00
34	311.00 WY	145,500	51.14	-8.00	1.87		23.20
35	312.00 WY	957,963	35.97	-7.00	2.86		22.00
36	314.00 WY	204,971	31.25	-8.00	3.36		21.70
37	315.00 WY	60,997	49.15	-7.00	1.93		22.40
38	316.00 WY	4,187	33.02	-8.00	3.12		18.50
39	Naughton Plant						
40	310.20 WY	15	66.74		1.45		16.00
41	311.00 WY	119,098	24.81	-5.00	4.34		15.80
42	312.00 WY	512,916	22.44	-4.00	4.81		15.40
43	314.00 WY	82,508	25.92	-6.00	4.17		15.00
44	315.00 WY	65,202	21.19	-4.00	5.13		15.80
45	316.00 WY	2,331	21.86	-6.00	5.15		13.90
46	Wyodak Plant						
47	310.20 WY	165	57.58		1.65		26.00
48	311.00 WY	51,567	51.08	-5.00	2.01		25.10
49	312.00 WY	312,349	34.28	-4.00	3.09		23.90
50	314.00 WY	66,458	34.60	-6.00	3.12		22.90

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 2016/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	315.00 WY	28,640	42.62	-4.00	2.44		24.60
13	316.00 WY	1,237	26.65	-6.00	4.07		21.10
14							
15	HYDRAULIC						
16	Ashton						
17	330.20 ID	328	40.48		2.79		14.00
18	331.00 ID	2,020	34.65	-2.00	3.33		13.80
19	332.00 ID	28,108	17.43	-1.00	6.19		13.90
20	333.00 ID	1,958	35.43	-2.00	3.21		13.60
21	334.00 ID	1,326	30.80	-3.00	3.77		13.00
22	335.00 ID	8	41.77	-1.00	2.82		13.20
23	336.00 ID	6	96.08	-5.00	1.64		13.50
24	Bear River						
25	330.20 ID	6	115.28		1.38		19.80
26	331.00 ID	4,869	38.54	-3.00	3.09		19.30
27	332.00 ID	28,257	34.60	-2.00	3.31		19.60
28	333.00 ID	11,711	33.28	-4.00	3.50		19.20
29	334.00 ID	5,113	30.59	-4.00	3.79		18.20
30	335.00 ID	82	42.57	-1.00	2.73		18.50
31	336.00 ID	844	40.28	-3.00	2.94		19.40
32	Bend						
33	331.00 OR	57	32.00		2.09		3.00
34	332.00 OR	1,161	8.74		17.64		3.00
35	333.00 OR	107	18.04	-1.00	6.79		3.00
36	334.00 OR	628	25.63		3.53		3.00
37	335.00 OR	15	15.79		3.38		3.00
38	336.00 OR		86.23				
39	Big Fork						
40	331.00 MT	606	52.37	-5.00	1.41		38.30
41	332.00 MT	4,855	53.78	-4.00	1.29		38.70
42	333.00 MT	1,496	50.44	-8.00	1.46		37.20
43	334.00 MT	404	46.04	-8.00	1.52		33.00
44	336.00 MT	234	45.15	-4.00	2.13		38.40
45	Cutler						
46	330.20 UT	1			8.34		
47	330.30 UT	5	96.37		3.11		11.00
48	330.40 UT	91	74.44		3.33		11.00
49	331.00 UT	3,987	28.62	-1.00	5.06		10.80
50	332.00 UT	9,178	30.30	-1.00	5.01		10.80

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	333.00 UT	12,000	17.15	-1.00	7.18		10.90
13	334.00 UT	2,691	17.22	-2.00	7.29		10.60
14	335.00 UT	11	36.34	-1.00	4.52		10.60
15	336.00 UT	572	35.14	-1.00	4.54		10.80
16	Eagle Point						
17	330.20 OR	12	68.49				
18	331.00 OR	141	33.98	-1.00	1.31		11.90
19	332.00 OR	1,233	33.88	-1.00	1.25		11.90
20	333.00 OR	252	42.71	-4.00	0.31		11.80
21	334.00 OR	135	25.76	-2.00	2.68		11.50
22	336.00 OR	179	24.29	-1.00	2.96		11.90
23	Granite						
24	331.00 UT	535	25.43	-2.00	4.42		16.70
25	332.00 UT	3,768	30.19	-1.00	3.60		16.80
26	333.00 UT	721	38.99	-4.00	3.06		16.30
27	334.00 UT	215	31.63	-3.00	3.63		15.60
28	335.00 UT	1	48.73	-2.00	2.45		16.00
29	Klamath River						
30	330.20 CA/OR	639	24.88		7.02		7.00
31	330.40 CA/OR	253	48.84		5.27		7.00
32	331.00 CA/OR	914	21.42	-1.00	7.87		6.90
33	332.00 CA/OR	11,773	40.24	-1.00	5.79		6.90
34	333.00 CA/OR	315	43.09	-3.00	5.84		6.70
35	334.00 CA/OR	874	19.24	-1.00	8.32		6.80
36	335.00 CA/OR	62	29.11	-1.00	6.92		6.80
37	336.00 CA/OR	241	23.60	-1.00	7.41		6.90
38	Klamath River Accel						
39	330.20 CA/OR	41			1.87		3.00
40	330.40 CA/OR	1			1.37		3.00
41	331.00 CA/OR	15,590			9.35		3.00
42	332.00 CA/OR	36,860			8.57		3.00
43	333.00 CA/OR	17,983			7.31		3.00
44	334.00 CA/OR	16,057			8.66		3.00
45	335.00 CA/OR	183			5.73		3.00
46	336.00 CA/OR	2,595			7.39		3.00
47	Last Chance						
48	331.00 ID	448	35.19	-1.00	3.45		11.80
49	332.00 ID	958	29.40	-1.00	4.03		11.90
50	333.00 ID	1,068	36.38	-2.00	3.35		11.70

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 2016/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	334.00 ID	266	22.78	-2.00	5.03		11.40
13	336.00 ID	65	40.81	-1.00	3.07		11.80
14	Lifton						
15	330.20 ID	21	99.80		1.87		20.00
16	330.30 ID	24	92.81		1.93		20.00
17	331.00 ID	1,230	51.97	-4.00	2.80		19.10
18	332.00 ID	8,270	40.45	-3.00	3.17		19.50
19	333.00 ID	7,875	26.40	-2.00	4.13		19.70
20	334.00 ID	377	36.10	-4.00	3.53		18.00
21	335.00 ID	12	46.32	-2.00	2.97		18.30
22	336.00 ID	187	29.39	-2.00	3.83		19.60
23	Merwin						
24	330.20 WA	301	121.57		0.50		45.00
25	330.50 WA	212	125.02		0.48		45.00
26	331.00 WA	91,202	48.18	-4.00	2.11		42.90
27	332.00 WA	30,141	54.60	-6.00	1.83		43.10
28	333.00 WA	8,205	65.82	-16.00	1.44		37.20
29	334.00 WA	9,847	44.36	-8.00	2.34		36.30
30	335.00 WA	169	48.09	-3.00	2.07		38.40
31	336.00 WA	3,963	59.30	-5.00	1.62		42.40
32	North Umpqua						
33	331.00 OR	33,546	27.53	-2.00	3.82		24.40
34	332.00 OR	199,120	38.59	-2.00	2.90		24.40
35	333.00 OR	25,615	34.44	-4.00	3.27		24.00
36	334.00 OR	19,204	29.42	-4.00	3.75		22.60
37	335.00 OR	722	36.23	-2.00	3.05		22.90
38	336.00 OR	9,570	41.97	-3.00	2.73		24.20
39	Paris						
40	331.00 ID	110	10.31		10.16		4.00
41	332.00 ID	102	46.25	-1.00			
42	333.00 ID	73	31.74	-1.00			
43	334.00 ID	162	14.62	-1.00	4.90		4.00
44	335.00 ID		34.25				
45	Pioneer						
46	330.20 UT	9	134.02		1.09		17.00
47	330.30 UT	111	133.34		1.09		17.00
48	331.00 UT	508	32.02	-2.00	3.54		16.60
49	332.00 UT	8,185	37.80	-2.00	2.97		16.70
50	333.00 UT	1,616	25.26	-2.00	4.31		16.70

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	334.00 UT	944	30.51	-3.00	3.67		15.60
13	335.00 UT	10	39.03	-1.00	2.85		16.00
14	336.00 UT	61	21.11	-1.00	5.17		16.70
15	Prospect No. 1, 2 & 4						
16	330.20 OR	4	56.24		2.02		25.30
17	330.40 OR	3	102.16		1.36		24.90
18	331.00 OR	3,906	40.66	-3.00	2.77		24.20
19	332.00 OR	34,179	32.55	-2.00	3.27		24.60
20	333.00 OR	3,898	35.11	-4.00	3.18		24.00
21	334.00 OR	6,791	33.85	-5.00	3.34		22.20
22	335.00 OR	19	35.19	-2.00	3.05		23.10
23	336.00 OR	339	39.57	-3.00	2.84		24.20
24	Prospect No. 3						
25	331.00 OR	644	21.27		5.46		5.00
26	332.00 OR	4,333	25.67		4.15		5.00
27	333.00 OR	1,812	21.89		4.76		5.00
28	334.00 OR	1,887	21.02	-1.00	5.25		4.90
29	335.00 OR	63	25.01		4.22		4.90
30	336.00 OR	117	36.09	-1.00	3.29		5.00
31	Santa Clara						
32	331.00 UT	180	23.79	-1.00	5.05		6.90
33	332.00 UT	1,139	24.52	-1.00	4.92		7.00
34	333.00 UT	464	26.11	-1.00	4.44		6.90
35	334.00 UT	702	20.82	-1.00	5.46		6.80
36	335.00 UT	8	32.24	-1.00	3.62		6.80
37	336.00 UT	22	80.51	-2.00	1.79		6.80
38	Stairs						
39	331.00 UT	181	39.40	-3.00	2.38		16.60
40	332.00 UT	811	28.73	-2.00	3.56		16.80
41	333.00 UT	518	36.73	-3.00	2.52		16.50
42	334.00 UT	176	33.10	-3.00	2.83		15.60
43	336.00 UT	33	19.20	-1.00	5.08		16.80
44	Swift No. 1						
45	330.20 WA	6,277	99.73		0.86		45.00
46	330.50 WA	97	98.01		0.88		45.00
47	331.00 WA	72,455	46.22	-4.00	2.26		43.00
48	332.00 WA	47,056	70.57	-7.00	1.40		42.00
49	333.00 WA	16,406	65.49	-16.00	1.63		37.00
50	334.00 WA	7,905	45.90	-8.00	2.29		35.90

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	335.00 WA	411	64.91	-5.00	1.46		34.20
13	336.00 WA	1,133	52.23	-5.00	1.98		42.70
14	Viva Naughton						
15	331.00 WY	403	49.70	-3.00	2.15		26.10
16	332.00 WY	104	51.79	-2.00	2.04		26.30
17	333.00 WY	497	49.03	-7.00	2.26		25.10
18	334.00 WY	207	42.11	-6.00	2.63		23.20
19	335.00 WY	21	46.04	-2.00	2.29		24.30
20	Wallowa Falls						
21	331.00 OR	168	23.24		4.41		3.00
22	332.00 OR	918	23.14		4.39		3.00
23	333.00 OR	807	15.16		9.10		3.00
24	334.00 OR	741	18.38		4.99		3.00
25	336.00 OR	649	20.11		4.76		3.00
26	Weber						
27	331.00 UT	368	34.24	-1.00	3.55		6.90
28	332.00 UT	1,999	32.11	-1.00	3.90		6.90
29	333.00 UT	943	28.58	-1.00	4.14		6.90
30	334.00 UT	258	12.47	-1.00	9.75		6.80
31	335.00 UT	22	28.45		3.97		6.80
32	336.00 UT	40	25.64	-1.00	4.36		6.90
33	Yale						
34	330.20 WA	762	103.77		0.82		45.00
35	331.00 WA	16,289	62.83	-6.00	1.60		42.10
36	332.00 WA	32,330	70.68	-8.00	1.40		41.80
37	333.00 WA	12,573	63.81	-15.00	1.68		37.70
38	334.00 WA	3,512	48.93	-9.00	2.14		35.00
39	335.00 WA	547	66.44	-5.00	1.40		33.00
40	336.00 WA	2,040	57.33	-5.00	1.76		42.50
41							
42	OTHER PRODUCTION						
43	Chehalis						
44	341.00 WA	24,163	39.75	-3.00	2.65		29.50
45	342.00 WA	1,597	36.50	-2.00	2.87		26.90
46	343.00 WA	212,870	35.70	-4.00	3.04		26.80
47	344.00 WA	70,039	36.45	-4.00	2.94		26.90
48	345.00 WA	39,304	39.21	-3.00	2.69		29.20
49	346.00 WA	3,269	38.83	-1.00	2.66		28.80
50							

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Currant Creek						
13	341.00 UT	44,165	39.83	-3.00	2.59		31.50
14	342.00 UT	3,300	36.50	-2.00	2.80		28.70
15	343.00 UT	194,855	35.19	-4.00	3.01		28.80
16	344.00 UT	63,110	36.06	-4.00	2.91		28.80
17	345.00 UT	42,881	39.03	-3.00	2.64		31.20
18	346.00 UT	2,983	39.06	-1.00	2.59		30.70
19	Hermiston						
20	341.00 OR	12,845	38.73	-3.00	2.90		22.60
21	342.00 OR	25	36.50	-2.00	3.08		20.70
22	343.00 OR	112,132	33.48	-4.00	3.42		20.80
23	344.00 OR	41,650	35.85	-3.00	3.16		20.80
24	345.00 OR	9,768	39.23	-3.00	2.88		22.40
25	346.00 OR	169	39.06	-1.00	2.84		22.00
26	Lake Side/Lake Side 2						
27	341.00 UT	88,654	39.96	-4.00	2.77		33.50
28	342.00 UT	8,507	36.50	-3.00	3.01		30.60
29	343.00 UT	549,525	36.11	-4.00	3.11		30.40
30	344.00 UT	222,706	36.40	-4.00	3.05		30.60
31	345.00 UT	119,843	39.46	-3.00	2.77		33.10
32	346.00 UT	6,122	39.06	-1.00	2.75		32.70
33	Gadsby Peakers						
34	341.00 UT	4,273	29.80	-1.00	3.43		18.90
35	342.00 UT	2,748	28.45	-1.00	3.61		18.00
36	343.00 UT	55,199	26.97	-2.00	3.91		18.10
37	344.00 UT	17,487	28.61	-2.00	3.64		18.00
38	345.00 UT	2,901	28.31	-1.00	3.62		18.80
39							
40	WIND GENERATION						
41	Dunlap Ranch 1						
42	341.00 WY	7,804	28.47	-1.00	3.49		25.30
43	343.00 WY	207,507	29.58	-1.00	3.34		26.20
44	344.00 WY	6,565	29.59	-1.00	3.34		26.20
45	345.00 WY	12,311	29.93		3.26		26.50
46	346.00 WY	149	29.94		3.25		26.50
47	Foote Creek						
48	341.00 WY	113	29.33	-1.00	3.49		15.30
49	343.00 WY	32,100	30.37	-1.00	2.84		15.50
50	344.00 WY	1,684	30.49	-1.00	2.83		15.50

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 2016/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	345.00 WY	2,927	30.96	-1.00	2.78		15.70
13	Glenrock/Glenrock III						
14	341.00 WY	10,574	27.88	-1.00	3.53		23.50
15	343.00 WY	440,675	29.01	-1.00	3.37		24.30
16	344.00 WY	13,688	29.01	-1.00	3.37		24.30
17	345.00 WY	29,538	29.33		3.30		24.60
18	346.00 WY	1,663	29.44		3.28		24.60
19	Goodnoe Hills						
20	341.00 WA	5,477	28.49	-1.00	3.44		23.50
21	343.00 WA	163,281	29.53	-1.00	3.30		24.30
22	344.00 WA	4,403	29.46	-1.00	3.31		24.30
23	345.00 WA	10,272	29.73		3.24		24.50
24	346.00 WA	172	29.94		3.21		24.50
25	High Plains/McFadden						
26	341.00 WY	7,815	28.46	-1.00	3.47		24.40
27	343.00 WY	245,982	29.57	-1.00	3.32		25.20
28	344.00 WY	7,008	29.59	-1.00	3.32		25.20
29	345.00 WY	14,750	29.92		3.23		25.50
30	346.00 WY	114	29.94		3.23		25.50
31	Leaning Juniper 1						
32	341.00 OR	4,965	28.49	-1.00	3.39		21.70
33	343.00 OR	158,232	29.47	-1.00	3.25		22.30
34	344.00 OR	5,378	29.36	-1.00	3.28		22.30
35	345.00 OR	9,175	29.70	-1.00	3.23		22.60
36	346.00 OR	81	29.94		3.16		22.60
37	Marengo/Marengo II						
38	341.00 WA	10,220	28.15	-1.00	3.47		22.60
39	343.00 WA	328,664	29.23	-1.00	3.32		23.30
40	344.00 WA	11,036	29.22	-1.00	3.32		23.30
41	345.00 WA	19,742	29.57	-1.00	3.27		23.60
42	346.00 WA	337	29.48		3.25		23.60
43	Seven Mile Hill						
44	341.00 WY	6,355	28.38	-1.00	3.45		23.50
45	343.00 WY	216,059	29.56	-1.00	3.29		24.30
46	344.00 WY	6,606	29.59	-1.00	3.29		24.30
47	345.00 WY	13,346	29.86		3.22		24.50
48	346.00 WY	802	29.78		3.23		24.50
49							
50							

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 2016/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	SOLAR GENERATING						
13	344.00 OR	56	19.88				
14	344.00 UT	36	20.49				
15	344.00 WY	6	20.46		4.11		14.00
16	344.00 WY	55	20.42				
17							
18	MOBILE GENERATOR						
19	East Side						
20	344.00 UT	840	50.00	-5.00	1.60	R2	42.50
21	West Side						
22	344.00 OR	849	50.00	-5.00	1.80	R2	46.00
23							
24	TRANSMISSION PLANT						
25	350.20	199,737	75.00		1.27	R4	63.50
26	352.00	242,604	75.00	-10.00	1.42	R2.5	66.40
27	353.00	2,031,695	58.00	-5.00	1.74	S0	48.90
28	354.00	1,290,262	68.00	-10.00	1.53	R4	55.70
29	355.00	915,984	60.00	-40.00	2.18	R2	46.10
30	356.00	1,209,045	63.00	-30.00	1.88	R3	46.00
31	357.00	3,519	60.00		1.60	R2	48.50
32	358.00	8,035	60.00	-5.00	1.66	R2	48.20
33	359.00	11,937	70.00		1.32	R5	49.40
34							
35	DISTRIBUTION PLANT						
36	360.20 OR	4,761	55.00		1.21	S3	36.80
37	361.00 OR	29,390	60.00	-10.00	1.79	R1.5	49.80
38	362.00 OR	239,713	55.00	-15.00	1.94	R1	43.50
39	364.00 OR	370,703	55.00	-100.00	3.29	R1.5	42.00
40	365.00 OR	257,650	60.00	-70.00	2.63	R0.5	47.40
41	366.00 OR	92,669	70.00	-50.00	1.97	R2.5	54.60
42	367.00 OR	177,017	58.00	-35.00	2.11	R2.5	43.70
43	368.00 OR	435,234	42.00	-20.00	2.44	R1.5	29.00
44	369.10 OR	88,752	55.00	-35.00	2.28	R1	42.50
45	369.20 OR	179,268	55.00	-40.00	2.34	R4	41.30
46	370.00 OR	63,499	27.00	-4.00	3.60	R1	17.90
47	371.00 OR	2,614	25.00	-50.00	4.79	L0	14.30
48	373.00 OR	23,386	44.00	-40.00	2.91	R0.5	33.80
49	360.20 WA	458	50.00		1.63	R3	24.50
50	361.00 WA	4,174	60.00	-5.00	1.64	R2	42.10

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	362.00 WA	61,975	53.00	-20.00	2.14	R1	38.90
13	364.00 WA	103,865	52.00	-100.00	3.64	R1.5	39.40
14	365.00 WA	68,926	60.00	-60.00	2.51	R1	45.10
15	366.00 WA	17,818	50.00	-50.00	2.84	R3	35.40
16	367.00 WA	26,735	50.00	-35.00	2.56	R3	36.80
17	368.00 WA	110,091	43.00	-25.00	2.64	R2	28.90
18	369.10 WA	22,170	55.00	-30.00	2.27	R1	41.90
19	369.20 WA	38,806	55.00	-50.00	2.63	R4	41.30
20	370.00 WA	12,336	25.00	-1.00	3.93	S5	21.20
21	371.00 WA	508	30.00	-25.00	3.48	L0	15.50
22	373.00 WA	4,454	45.00	-30.00	2.64	R1	31.70
23	360.20 WY	5,866	50.00		1.99	R4	33.50
24	361.00 WY	16,949	60.00	-10.00	1.83	R2.5	49.90
25	362.00 WY	134,615	55.00	-10.00	1.99	R1	42.20
26	364.00 WY	151,693	50.00	-100.00	3.99	R1	39.10
27	365.00 WY	108,745	57.00	-40.00	2.45	R0.5	44.20
28	366.00 WY	26,374	42.00	-40.00	3.32	R3	30.60
29	367.00 WY	60,675	40.00	-35.00	3.35	R4	26.20
30	368.00 WY	118,277	39.00	-25.00	3.19	R1	28.90
31	369.10 WY	19,103	60.00	-25.00	2.08	R1.5	47.20
32	369.20 WY	43,002	55.00	-50.00	2.72	R4	44.10
33	370.00 WY	15,206	25.00	-2.00	4.04	S5	20.60
34	371.00 WY	968	25.00	-60.00	6.10	O1	12.20
35	373.00 WY	10,653	50.00	-45.00	2.89	R0.5	38.90
36	360.20 CA	1,087	55.00		2.31	R4	20.10
37	361.00 CA	5,128	55.00	-5.00	2.05	R4	37.62
38	362.00 CA	28,372	55.00	-25.00	2.39	R1	41.60
39	362.70 CA	396	20.00		7.06	R5	5.47
40	364.00 CA	64,671	50.00	-90.00	3.80	R1.5	37.94
41	365.00 CA	35,406	65.00	-95.00	3.12	S-.5	51.70
42	366.00 CA	17,546	50.00	-45.00	2.99	R5	34.58
43	367.00 CA	19,559	45.00	-40.00	2.43	S6	29.50
44	368.00 CA	52,611	50.00	-25.00	2.53	R5	32.34
45	369.10 CA	9,701	55.00	-15.00	1.78	R1	44.37
46	369.20 CA	15,899	60.00	-20.00	1.81	R4	48.69
47	370.00 CA	4,163	26.00	-4.00	4.60	R2.5	13.24
48	371.00 CA	275	25.00	-40.00	4.81	L0	13.85
49	373.00 CA	726	35.00	-26.00	3.03	R3	16.36
50	360.20 UT	10,839	60.00		1.66	R4	49.60

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	361.00 UT	54,386	60.00		1.66	S0.5	50.90
13	362.00 UT	466,986	47.00	-10.00	2.34	R0.5	39.70
14	364.00 UT	369,852	50.00	-80.00	3.59	R0.5	39.60
15	365.00 UT	229,655	52.00	-45.00	2.78	R0.5	40.20
16	366.00 UT	194,144	60.00	-50.00	2.49	R2	49.00
17	367.00 UT	527,458	50.00	-25.00	2.49	R2	38.80
18	368.00 UT	509,612	45.00	-5.00	2.33	R0.5	36.30
19	369.00 UT	287,981	55.00	-25.00	2.27	S5	44.60
20	370.00 UT	82,636	25.00	-2.00	3.90	S5	16.90
21	371.00 UT	4,303	25.00	-60.00	6.37	L0	16.80
22	373.00 UT	21,965	25.00	-20.00	4.78	R0.5	16.90
23	360.20 ID	1,312	50.00		1.99	R4	34.20
24	361.00 ID	2,326	60.00		1.66	R2	48.90
25	362.00 ID	31,069	55.00	-10.00	1.99	R1.5	41.20
26	364.00 ID	85,814	50.00	-80.00	3.59	R0.5	39.50
27	365.00 ID	37,099	52.00	-30.00	2.49	R0.5	36.30
28	366.00 ID	9,524	60.00	-40.00	2.33	R2	48.90
29	367.00 ID	27,071	50.00	-15.00	2.29	R2	37.80
30	368.00 ID	79,606	45.00	-5.00	2.33	R0.5	34.20
31	369.00 ID	38,808	55.00	-25.00	2.27	S5	44.00
32	370.00 ID	15,113	25.00	-3.00	3.95	S5	13.10
33	371.00 ID	169	25.00	-45.00	5.77	L0	16.80
34	373.00 ID	707	25.00	-20.00	4.78	R0.5	16.90
35							
36	GENERAL PLANT						
37	390.00 OR	83,075	58.00	-10.00	1.86	R1	47.20
38	392.01 OR	10,090	12.00	10.00	7.04	L2.5	6.90
39	392.05 OR	13,186	16.00	10.00	5.48	L3	8.70
40	392.09 OR	3,436	34.00	15.00	2.44	L2	23.70
41	396.03 OR	8,198	9.00	15.00	9.23	L3	5.50
42	396.07 OR	28,563	15.00	20.00	5.14	L1	9.80
43	390.00 WA	12,982	40.00	-10.00	2.52	R3	24.70
44	392.01 WA	2,081	13.00	10.00	5.60	L2.5	8.10
45	392.05 WA	4,989	16.00	10.00	5.07	L2.5	9.60
46	392.09 WA	756	33.00	15.00	2.38	S0.5	24.10
47	396.03 WA	1,845	10.00	10.00	5.66	R4	7.30
48	396.07 WA	6,276	13.00	15.00	6.03	L1.5	8.00
49	389.20 WY	74	50.00		1.98	SQ	43.40
50	390.00 WY	11,207	58.00	-15.00	1.95	R1	47.70

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	392.01 WY	4,968	13.00	10.00	5.85	S1.5	6.10
13	392.05 WY	6,736	15.00	10.00	5.66	L1.5	9.20
14	392.09 WY	3,642	34.00	5.00	2.68	L2	23.20
15	396.03 WY	4,416	9.00	15.00	8.47	L3	5.30
16	396.07 WY	35,874	15.00	25.00	4.86	L0	11.60
17	390.00 CA	3,322	60.00	-20.00	1.71	R3	46.30
18	392.01 CA	825	10.00	20.00	3.48	S3	6.60
19	392.05 CA	1,238	15.00	15.00	4.49	L2	9.10
20	392.09 CA	488	35.00	5.00	2.32	R2	26.20
21	396.03 CA	1,220	8.00	15.00	7.20	R4	4.30
22	396.07 CA	3,038	14.00	15.00	4.98	L1.5	9.20
23	389.20 UT	85	45.00		2.03	S0	36.20
24	390.00 UT	92,677	58.00	5.00	1.53	R1	44.60
25	392.01 UT	16,552	12.00	10.00	5.04	L3	5.50
26	392.05 UT	22,739	16.00	10.00	4.56	L2	9.20
27	392.09 UT	7,780	34.00	25.00	1.91	L2	22.40
28	392.30 UT	3,076	10.00	64.00	2.51	SQ	5.30
29	396.03 UT	8,573	9.00	10.00	8.10	L3	5.70
30	396.07 UT	52,571	14.00	15.00	5.36	L0.5	9.90
31	389.20 ID	5	55.00		1.17	R3	25.10
32	390.00 ID	12,821	58.00	-5.00	1.65	R1	43.40
33	392.01 ID	2,672	12.00	10.00	4.28	S2	7.00
34	392.05 ID	3,283	15.00	15.00	4.34	L2	8.80
35	392.09 ID	1,058	34.00	10.00	2.28	L2	24.40
36	396.03 ID	2,467	9.00	10.00	7.67	L3	5.90
37	396.07 ID	7,112	18.00	25.00	3.73	L0.5	13.10
38	AZ, CO, MT, Etc.						
39	390.00	385	45.00		1.51	R2	25.10
40	392.01	587	16.00		2.53	R2	10.70
41	392.05	319	19.00	15.00	2.10	R2.5	13.70
42	392.09	9	25.00		2.18	R1.5	12.80
43	396.07	2,390	25.00	5.00	1.86	R2	17.80
44	All States						
45	391.00	27,571	20.00		5.00		
46	391.20	46,551	5.00		20.00		
47	391.30	492	8.00		12.50		
48	393.00	15,364	25.00		4.00		
49	394.00	63,198	24.00		4.17		
50	395.00	32,518	20.00		5.00		

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	397.00	423,406	24.00		4.30		
13	397.20	11,934	11.00		9.09		
14	398.00	7,995	20.00		5.00		
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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, 2016, depreciation expense associated with transportation equipment was $14,483,977.

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.: 12 Column: a

The Oregon Public Utility Commission required modifications related to the depreciable lives of coal-fired generating facilities. Below are the affected facilities and the lives and rates required by Oregon.

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)
STEAM PRODUCTION PLANT						
Cholla Plant						
310.20 AZ	1,368			5.72		15.00
311.00 AZ	64,183		-5.00	4.04		14.70
312.00 AZ	339,497		-4.00	4.94		14.20
314.00 AZ	67,634		-5.00	4.67		13.80
315.00 AZ	68,727		-4.00	3.98		14.60
316.00 AZ	4,094		-5.00	4.92		13.00
Colstrip Plant						
311.00 MT	61,428		-5.00	2.31		18.40
312.00 MT	119,477		-5.00	2.81		16.80
314.00 MT	38,426		-6.00	3.34		17.00
315.00 MT	9,224		-4.00	2.16		18.20
316.00 MT	397		-6.00	3.24		15.70
Craig Plant						
311.00 CO	38,324		-5.00	2.92		12.70
312.00 CO	96,437		-5.00	4.37		12.20
314.00 CO	28,715		-6.00	5.06		12.20
315.00 CO	17,066		-4.00	2.80		12.60
316.00 CO	1,240		-6.00	3.98		11.30
Dave Johnston Plant						
310.20 WY	100			3.18		10.00
311.00 WY	158,156		-4.00	7.50		9.90
312.00 WY	689,845		-4.00	7.66		9.80
314.00 WY	96,287		-4.00	6.32		9.60
315.00 WY	62,765		-3.00	7.70		9.90
316.00 WY	8,418		-4.00	7.69		9.30
Hayden Plant						
311.00 CO	17,688		-5.00	7.49		9.90
312.00 CO	82,794		-5.00	4.62		9.60
314.00 CO	9,633		-5.00	5.65		9.60
315.00 CO	2,555		-4.00	2.59		9.70
316.00 CO	637		-5.00	4.36		9.00
Hunter Plant						
310.20 UT	246			2.43		16.00
311.00 UT	209,648		-6.00	2.84		15.50
312.00 UT	758,565		-5.00	4.36		15.00
314.00 UT	200,440		-6.00	4.84		15.00
315.00 UT	107,848		-5.00	2.88		15.40
316.00 UT	3,691		-6.00	4.00		13.50

FOOTNOTE DATA

Huntington Plant				
311.00 UT	124,429	-7.00	3.06	16.50
312.00 UT	563,304	-6.00	4.70	16.10
314.00 UT	123,318	-7.00	4.37	15.70
315.00 UT	47,559	-5.00	3.51	16.50
316.00 UT	2,890	-6.00	4.77	14.70
Jim Bridger Plant				
310.20 WY	281		2.43	12.00
311.00 WY	145,500	-7.00	3.19	11.70
312.00 WY	957,963	-6.00	4.85	11.40
314.00 WY	204,971	-7.00	5.78	11.50
315.00 WY	60,997	-6.00	3.36	11.70
316.00 WY	4,187	-7.00	4.71	10.60
Naughton Plant				
310.20 WY	15		1.60	15.00
311.00 WY	119,098	-5.00	4.63	14.80
312.00 WY	512,916	-5.00	5.21	14.40
314.00 WY	82,508	-6.00	4.44	14.00
315.00 WY	65,202	-4.00	5.46	14.80
316.00 WY	2,331	-5.00	5.38	13.10
Wyodak Plant				
310.20 WY	165		2.84	13.00
311.00 WY	51,567	-4.00	3.41	12.70
312.00 WY	312,349	-3.00	5.43	12.40
314.00 WY	66,458	-4.00	5.27	12.20
315.00 WY	28,640	-3.00	4.34	12.70
316.00 WY	1,237	-4.00	6.52	11.80

Schedule Page: 336.3 Line No.: 38 Column: a

The depreciation rate changes 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.

Schedule Page: 336.8 Line No.: 25 Column: a

High Plains and McFadden Ridge I wind plants

Schedule Page: 336.8 Line No.: 43 Column: a

Seven Mile Hill and Seven Mile Hill II wind plants

Schedule Page: 336.13 Line No.: 16 Column: a

FERC Sub Acct	Description
310.20	Land Rights
330.20	Land Rights
330.30	Water Rights
330.40	Flood Rights
330.50	Fish/Wildlife
350.20	Land Rights
360.20	Land Rights
369.10	Overhead Services
369.20	Underground Services
389.20	Land Rights
391.20	Personal Computers and Printers
391.30	Office Equipment
392.01	Transportation Equipment - Light Trucks and Vans
392.05	Transportation Equipment - Medium Trucks
392.09	Transportation Equipment - Trailers
392.30	Aircraft
396.03	Light Power Operated Equipment
396.07	Heavy Power Operated Equipment
397.20	Mobile Radio Equipment

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 2016/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	5,883,815		5,883,815	
3	Rate Cases and Proceedings		635,251	635,251	
4					
5	Oregon Public Utility Commission:				
6	Annual Fee	3,375,083		3,375,083	
7	Rate Cases and Proceedings		1,355,979	1,355,979	
8	Deferred Intervenor Funding Grants (1)		1,290,508	1,290,508	1,442,958
9					
10	Wyoming Public Service Commission:				
11	Annual Fee	1,728,796		1,728,796	
12	Rate Cases and Proceedings		241,290	241,290	
13					
14	Washington Utilities and Transportation				
15	Commission:				
16	Annual Fee	663,716		663,716	
17	Rate Cases and Proceedings		1,062,472	1,062,472	
18					
19	Idaho Public Utilities Commission:				
20	Annual Fee	616,685		616,685	
21	Rate Cases and Proceedings		29,228	29,228	
22	Deferred Intervenor Funding Grants				26,865
23					
24	California Public Utilities Commission:				
25	Annual Fee	428		428	
26	Rate Cases and Proceedings		206,410	206,410	
27	Deferred Intervenor Funding Grants				40,406
28					
29	California Environmental Protection Agency:				
30	Industry Compliance Fee	8,149	11,688	19,837	
31					
32	Multi-State:				
33	Rate Cases and Proceedings		290,475	290,475	
34	Other Regulatory		2,469,236	2,469,236	
35					
36	Federal Energy Regulatory Commission:				
37	Annual Fee	1,913,622		1,913,622	
38	Annual Fee - Hydroelectric Plants	2,289,581		2,289,581	
39	Transmission Rate Cases		206,206	206,206	
40	Other Regulatory		983,203	983,203	
41					
42					
43					
44					
45					
46	TOTAL	16,479,875	8,781,946	25,261,821	1,510,229

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	5,883,815					2
Electric	928	635,251					3
							4
							5
Electric	928	3,375,083					6
Electric	928	1,355,979					7
Electric	928	1,290,508	258,463	928	1,290,508	410,913	8
							9
							10
Electric	928	1,728,796					11
Electric	928	241,290					12
							13
							14
							15
Electric	928	663,716					16
Electric	928	1,062,472					17
							18
							19
Electric	928	616,685					20
Electric	928	29,228					21
						26,865	22
							23
							24
Electric	928	428					25
Electric	928	206,410					26
			199			40,605	27
							28
							29
Electric	928	19,837					30
							31
							32
Electric	928	290,475					33
Electric	928	2,469,236					34
							35
							36
Electric	928	1,913,622					37
Electric	928	2,289,581					38
Electric	928	206,206					39
Electric	928	983,203					40
							41
							42
							43
							44
							45
		25,261,821	258,662		1,290,508	478,383	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 2016/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
6		
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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 2016/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
	18,000	557	18,000		3
					4
9,340	8,170		17,510		5
					6
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Schedule Page: 352 Line No.: 5 Column: e

Account 920, Administrative and general salaries
Account 921, Office supplies and expenses
Account 930.2, Miscellaneous general expenses

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 2016/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	98,112,599		
4	Transmission	15,940,794		
5	Regional Market			
6	Distribution	37,509,679		
7	Customer Accounts	36,465,651		
8	Customer Service and Informational	6,453,618		
9	Sales			
10	Administrative and General	36,907,660		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	231,390,001		
12	Maintenance			
13	Production	46,060,558		
14	Transmission	11,350,883		
15	Regional Market			
16	Distribution	60,919,466		
17	Administrative and General	1,803,223		
18	TOTAL Maintenance (Total of lines 13 thru 17)	120,134,130		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	144,173,157		
21	Transmission (Enter Total of lines 4 and 14)	27,291,677		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	98,429,145		
24	Customer Accounts (Transcribe from line 7)	36,465,651		
25	Customer Service and Informational (Transcribe from line 8)	6,453,618		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	38,710,883		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	351,524,131		351,524,131
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

DISTRIBUTION OF SALARIES AND WAGES (Continued)

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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)	351,524,131		351,524,131
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	146,930,576		146,930,576
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	146,930,576		146,930,576
72	Plant Removal (By Utility Departments)			
73	Electric Plant	9,093,942		9,093,942
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	9,093,942		9,093,942
77	Other Accounts (Specify, provide details in footnote):			
78	Fuel Stock	4,097,632		4,097,632
79	Miscellaneous Other Income Deductions	317,159		317,159
80	Miscellaneous Non-Operating and Non-Utility	671,391		671,391
81	Charges to Affiliates	2,247,345		2,247,345
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	7,333,527		7,333,527
96	TOTAL SALARIES AND WAGES	514,882,176		514,882,176

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 2016/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)		670	(348,859)	(345,612)
3	Net Sales (Account 447)	(36,876)	(65,635)	(5,674)	(285,074)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7	Energy Imbalance Market (Account 555)	(5,579,386)	(8,396,637)	(25,701,586)	(44,490,036)
8					
9					
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45					
46	TOTAL	(5,616,262)	(8,461,602)	(26,056,119)	(45,120,722)

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				140,841,810	MWh	12,368,812
2	Reactive Supply and Voltage	22,130,990	MWh	7,926,328	30,315,023	MWh	8,437,982
3	Regulation and Frequency Response	94,005,892	MWh	31,468,440	104,304,475	MWh	35,383,473
4	Energy Imbalance				531,534	MWh	37,549,419
5	Operating Reserve - Spinning	119,156,856	MWh	46,471,174	124,766,043	MWh	48,682,409
6	Operating Reserve - Supplement	119,156,856	MWh	40,513,331	122,872,091	MWh	41,800,163
7	Other						
8	Total (Lines 1 thru 7)	354,450,594		126,379,273	523,630,976		184,222,258

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 2016/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: PacifiCorp

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	14,756	4	1800	8,559	141	3,545		976	1,535
2	February	14,645	2	800	8,290	140	3,545		1,145	1,525
3	March	13,654	29	800	7,490	127	3,545		1,141	1,351
4	Total for Quarter 1				24,339	408	10,635		3,262	4,411
5	April	12,980	14	1000	7,096	108	3,545		868	1,363
6	May	13,868	31	1700	7,783	111	3,545		908	1,521
7	June	18,098	28	1600	10,181	137	3,703		2,204	1,873
8	Total for Quarter 2				25,060	356	10,793		3,980	4,757
9	July	18,583	28	1700	10,402	398	3,650		2,222	1,911
10	August	17,553	16	1700	9,997	374	3,650		1,665	1,867
11	September	16,140	1	1500	8,825	332	3,650		1,738	1,595
12	Total for Quarter 3				29,224	1,104	10,950		5,625	5,373
13	October	13,509	19	800	7,260	360	3,650		981	1,258
14	November	14,671	30	1800	8,093	443	3,493		1,188	1,454
15	December	15,528	19	1800	8,914	550	3,493		1,074	1,497
16	Total for Quarter 4				24,267	1,353	10,636		3,243	4,209
17	Total Year to Date/Year				102,890	3,221	43,014		16,110	18,750

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 Daylight 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 2016 Net System Load information was compiled using metering and/or scheduling data. Reflects actual peak not 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 2016 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 2016 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 2016 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 2016 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 2016/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)	54,317,937
3	Steam	40,071,650			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	25,550
5	Hydro-Conventional	3,847,042			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	6,615,415
7	Other	9,655,266			
8	Less Energy for Pumping	3,617	25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	53,570,341	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	199,685
10	Purchases	11,939,781	27	Total Energy Losses	3,792,322
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	64,950,909
12	Received	5,901,498			
13	Delivered	6,217,758			
14	Net Exchanges (Line 12 minus line 13)	-316,260			
15	Transmission For Other (Wheeling)				
16	Received	13,233,893			
17	Delivered	13,121,145			
18	Net Transmission for Other (Line 16 minus line 17)	112,748			
19	Transmission By Others Losses	-355,701			
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	64,950,909			

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	6,094,203	852,302	8,342	4	1800 PST
30	February	5,297,964	709,000	8,068	2	0800 PST
31	March	4,842,980	323,345	7,211	15	0800 PDT
32	April	4,594,802	338,775	6,833	26	0800 PDT
33	May	4,895,352	408,120	7,463	31	1700 PDT
34	June	5,441,229	287,797	9,881	28	1600 PDT
35	July	6,076,173	492,881	10,139	28	1700 PDT
36	August	5,893,836	415,688	9,688	1	1700 PDT
37	September	5,200,709	610,867	8,512	1	1500 PDT
38	October	5,483,188	817,586	6,971	19	0800 PDT
39	November	4,943,360	584,824	7,858	30	1800 PST
40	December	6,187,113	774,230	8,708	14	1800 PST
41	TOTAL	64,950,909	6,615,415			

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 2016/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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Line No.	Item (a)	Plant Name: *Cholla* (b)			Plant Name: *Colstrip* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Full Outdoor			Conventional		
3	Year Originally Constructed	1981			1984		
4	Year Last Unit was Installed	1981			1986		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	414.00			155.61		
6	Net Peak Demand on Plant - MW (60 minutes)	378			164		
7	Plant Hours Connected to Load	6513			8483		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	395			148		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	1740097000			1035662000		
13	Cost of Plant: Land and Land Rights	2635317			1788644		
14	Structures and Improvements	65162618			61357810		
15	Equipment Costs	479923309			167304941		
16	Asset Retirement Costs	18682010			10334057		
17	Total Cost	566403254			240785452		
18	Cost per KW of Installed Capacity (line 17/5) Including	1368.1238			1547.3649		
19	Production Expenses: Oper, Supv, & Engr	3522859			39728		
20	Fuel	43275157			17338617		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	5702321			1029510		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	288658			102060		
26	Misc Steam (or Nuclear) Power Expenses	2033796			1644541		
27	Rents	0			27560		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	2698783			296544		
30	Maintenance of Structures	3378120			427980		
31	Maintenance of Boiler (or reactor) Plant	7088054			3045526		
32	Maintenance of Electric Plant	732402			660721		
33	Maintenance of Misc Steam (or Nuclear) Plant	2248891			438895		
34	Total Production Expenses	70969041			25051682		
35	Expenses per Net KWh	0.0408			0.0242		
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	1018837	4409	0	661422	1670	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9165	128094	0	8414	140000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	39.292	82.173	0.000	23.480	77.242	0.000
41	Average Cost of Fuel per Unit Burned	42.119	82.173	0.000	26.019	77.242	0.000
42	Average Cost of Fuel Burned per Million BTU	2.298	15.274	2.314	1.546	13.136	1.556
43	Average Cost of Fuel Burned per KWh Net Gen	0.025	0.000	0.025	0.017	0.000	0.017
44	Average BTU per KWh Net Generation	10731.888	13.632	10745.520	10746.890	9.479	10756.369

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

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Plant Name: *Craig* (d)	Plant Name: *Dave Johnston* (e)	Plant Name: *Hayden* (f)	Line No.
Steam	Steam	Steam	1
Outdoor Boiler	Semi-Outdoor	Outdoor Boiler	2
1979	1959	1965	3
1980	1972	1976	4
172.13	816.77	81.37	5
106	733	78	6
8767	8784	8784	7
0	0	0	8
165	760	78	9
0	0	0	10
0	191	0	11
1159892000	5088505000	494248000	12
137086	10449793	683069	13
38313686	157936331	17648897	14
143421146	856642283	95517478	15
35149	15604693	532363	16
181907067	1040633100	114381807	17
1056.8005	1274.0834	1405.7000	18
433775	364573	146701	19
21723740	59076306	12517365	20
0	0	0	21
1772870	4899813	1167316	22
0	0	0	23
0	0	0	24
831130	0	118464	25
1151556	15395646	542010	26
0	140452	0	27
0	0	0	28
866431	0	172799	29
585002	1997073	472020	30
3685825	8561766	1201528	31
1193162	8382540	436699	32
955745	1112630	461038	33
33199236	99930799	17235940	34
0.0286	0.0196	0.0349	35

(d) Coal	(d) Oil	(d) Composite	(e) Coal	(e) Oil	(e) Composite	(f) Coal	(f) Oil	(f) Composite	Line No.
Coal	Oil	Composite	Coal	Oil	Composite	Coal	Oil	Composite	36
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
580610	103	0	3533020	14452	0	240019	281	0	38
10054	133693	0	8115	138000	0	11283	137269	0	39
33.982	126.581	0.000	16.336	63.737	0.000	48.039	91.549	0.000	40
37.215	126.581	0.000	16.460	63.737	0.000	51.791	91.549	0.000	41
1.851	22.554	1.861	1.014	10.997	1.029	2.295	15.878	2.310	42
0.019	0.000	0.019	0.011	0.000	0.011	0.025	0.000	0.025	43
10065.291	0.500	10065.791	11268.467	16.461	11284.928	10958.275	3.277	10961.552	44

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

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Line No.	Item (a)	Plant Name: *Hunter Unit No. 1* (b)			Plant Name: *Hunter Unit No. 2* (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	1978			1980		
4	Year Last Unit was Installed	1978			1980		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	457.73			294.46		
6	Net Peak Demand on Plant - MW (60 minutes)	427			277		
7	Plant Hours Connected to Load	8365			8265		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	418			269		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	2688704000			1822963000		
13	Cost of Plant: Land and Land Rights	9688261			9688261		
14	Structures and Improvements	64118148			53434975		
15	Equipment Costs	379175160			245730984		
16	Asset Retirement Costs	4772870			4772870		
17	Total Cost	457754439			313627090		
18	Cost per KW of Installed Capacity (line 17/5) Including	1000.0534			1065.0923		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	53967964			34896801		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	5847967			5737017		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			658		
26	Misc Steam (or Nuclear) Power Expenses	1885054			-4679288		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	2562226			2430747		
31	Maintenance of Boiler (or reactor) Plant	4524990			4373656		
32	Maintenance of Electric Plant	1042348			1050448		
33	Maintenance of Misc Steam (or Nuclear) Plant	503393			282071		
34	Total Production Expenses	70333942			44092110		
35	Expenses per Net KWh	0.0262			0.0242		
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	1289443	1897	0	829859	1961	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11114	138000	0	11381	138000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	41.746	0.000	0.000	41.876	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	1.878	12.650	1.882	1.840	12.786	1.846
43	Average Cost of Fuel Burned per KWh Net Gen	0.020	0.000	0.020	0.019	0.000	0.019
44	Average BTU per KWh Net Generation	10660.410	4.089	10664.499	10362.193	6.235	10368.428

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

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Plant Name: *Hunter Unit No. 3* (d)			Plant Name: *Hunter - Total Plant* (e)			Plant Name: *Huntington* (f)			Line No.
Steam			Steam			Steam			1
Outdoor Boiler			Outdoor Boiler			Outdoor Boiler			2
1983			1978			1974			3
1983			1983			1977			4
495.59			1247.78			996.00			5
490			1380			896			6
6987			8784			8784			7
0			0			0			8
471			1158			909			9
0			0			0			10
0			215			163			11
2546078000			7057745000			5503890000			12
10274569			29651091			2377564			13
92084593			209637716			124305754			14
445391597			1070297741			736891364			15
4772870			14318610			10599560			16
552523629			1323905158			874174242			17
1114.8805			1061.0085			877.6850			18
0			0			17595			19
50509339			139374104			129979273			20
0			0			0			21
5855090			17440074			12839579			22
0			0			0			23
0			0			0			24
8339			8997			0			25
2824102			29868			4744631			26
0			0			4381			27
0			0			0			28
0			0			2161499			29
2872565			7865538			1915269			30
11786609			20685255			6249737			31
2765405			4858201			982216			32
415590			1201054			851235			33
77037039			191463091			159745415			34
0.0303			0.0271			0.0290			35
Coal	Oil	Composite	Coal	Oil	Composite	Coal	Oil	Composite	36
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
1183476	11320	0	3302778	15178	0	2478319	3565	0	38
11069	138000	0	11165	138000	0	11386	138000	0	39
0.000	0.000	0.000	41.279	75.044	0.000	51.957	76.637	0.000	40
41.957	0.000	0.000	41.854	75.044	0.000	52.336	76.637	0.000	41
1.895	13.025	1.923	1.874	12.947	1.888	2.298	13.222	2.302	42
0.020	0.000	0.020	0.020	0.000	0.020	0.024	0.000	0.024	43
10290.291	25.769	10316.060	10449.863	12.465	10462.328	10254.034	3.755	10257.789	44

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Line No.	Item (a)	Plant Name: *Jim Bridger* (b)			Plant Name: *Naughton* (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	1974			1963		
4	Year Last Unit was Installed	1979			1971		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	1550.65			707.20		
6	Net Peak Demand on Plant - MW (60 minutes)	1424			657		
7	Plant Hours Connected to Load	8782			8784		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	1415			637		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	341			129		
12	Net Generation, Exclusive of Plant Use - KWh	8017176000			4871839000		
13	Cost of Plant: Land and Land Rights	1193761			1043724		
14	Structures and Improvements	145431073			119021791		
15	Equipment Costs	1227685417			662796581		
16	Asset Retirement Costs	19665563			48259402		
17	Total Cost	1393975814			831121498		
18	Cost per KW of Installed Capacity (line 17/5) Including	898.9623			1175.2284		
19	Production Expenses: Oper, Supv, & Engr	14293869			393840		
20	Fuel	260003235			110299322		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	18416773			8987049		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			8372		
26	Misc Steam (or Nuclear) Power Expenses	-22603682			8619089		
27	Rents	290985			14350		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	671941			1722723		
30	Maintenance of Structures	9398336			2161509		
31	Maintenance of Boiler (or reactor) Plant	25100728			10258435		
32	Maintenance of Electric Plant	7298168			3220412		
33	Maintenance of Misc Steam (or Nuclear) Plant	1374619			877191		
34	Total Production Expenses	314244972			146562292		
35	Expenses per Net KWh	0.0392			0.0301		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil	Composite	Coal	Gas	Composite
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		Tons	MCF	
38	Quantity (Units) of Fuel Burned	4573314	12112	0	2637277	20779	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9089	138000	0	10060	1045	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	52.340	79.441	0.000	41.773	14.458	0.000
41	Average Cost of Fuel per Unit Burned	56.642	79.441	0.000	41.709	14.458	0.000
42	Average Cost of Fuel Burned per Million BTU	3.116	13.706	3.125	2.073	13.840	2.078
43	Average Cost of Fuel Burned per KWh Net Gen	0.032	0.000	0.032	0.023	0.000	0.023
44	Average BTU per KWh Net Generation	10369.428	8.756	10378.184	10891.221	4.455	10895.676

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Plant Name: *Wyodak* (d)	Plant Name: *Gadsby Steam* (e)	Plant Name: *Hermiston* (f)	Line No.
Steam	Steam	Combined Cycle	1
Conventional	Outdoor	Outdoor	2
1978	1951	1996	3
1978	1955	1996	4
289.66	251.64	279.56	5
274	155	246	6
6713	1345	3482	7
0	0	0	8
266	238	231	9
0	0	0	10
64	35	0	11
1614214000	63646000	1145656000	12
210526	1252090	842245	13
51512950	15094519	12840576	14
408388942	67593009	163692606	15
652977	1132809	407646	16
460765395	85072427	177783073	17
1590.7112	338.0720	635.9389	18
22952	57329	0	19
23143888	4109422	22887251	20
0	0	0	21
4198361	113156	0	22
0	0	0	23
0	0	0	24
0	0	6005506	25
2221871	3252383	0	26
13157	0	0	27
0	0	0	28
0	0	0	29
1006130	104584	0	30
6881914	1018008	0	31
2495800	1090349	0	32
208145	138058	0	33
40192218	9883289	28892757	34
0.0249	0.1553	0.0252	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Coal	Oil	Composite	Gas			Gas			36
Tons	Barrels		MCF			MCF			37
1229557	2388	0	1095361	0	0	8370040	0	0	38
8038	138000	0	1052	0	0	1033	0	0	39
18.544	73.704	0.000	3.752	0.000	0.000	2.734	0.000	0.000	40
18.680	73.704	0.000	3.752	0.000	0.000	2.734	0.000	0.000	41
1.162	12.717	1.170	3.565	0.000	0.000	2.648	0.000	0.000	42
0.014	0.000	0.014	0.065	0.000	0.000	0.020	0.000	0.000	43
12245.905	8.576	12254.481	18110.942	0.000	0.000	7544.034	0.000	0.000	44

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

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a 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: *Blundell* (b)			Plant Name: *Chehalis* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam - Geothermal			Combined Cycle		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Indoor			Outdoor		
3	Year Originally Constructed	1984			2003		
4	Year Last Unit was Installed	2007			2003		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	38.10			593.30		
6	Net Peak Demand on Plant - MW (60 minutes)	36			493		
7	Plant Hours Connected to Load	8556			5776		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	32			477		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	24			18		
12	Net Generation, Exclusive of Plant Use - KWh	256918000			1420028000		
13	Cost of Plant: Land and Land Rights	41195596			3730527		
14	Structures and Improvements	8293064			24162319		
15	Equipment Costs	101535008			327045288		
16	Asset Retirement Costs	2062367			1030777		
17	Total Cost	153086035			355968911		
18	Cost per KW of Installed Capacity (line 17/5) Including	4018.0062			599.9813		
19	Production Expenses: Oper, Supv, & Engr	4174			118811		
20	Fuel	0			46297239		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	927990			0		
23	Steam From Other Sources	4387771			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			1962926		
26	Misc Steam (or Nuclear) Power Expenses	1734057			688716		
27	Rents	6667			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	350635			33650		
31	Maintenance of Boiler (or reactor) Plant	461268			0		
32	Maintenance of Electric Plant	266551			1912719		
33	Maintenance of Misc Steam (or Nuclear) Plant	59646			0		
34	Total Production Expenses	8198759			51014061		
35	Expenses per Net KWh	0.0319			0.0359		
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	0	0	0	10082022	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	1087	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	4.592	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	4.592	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	4.223	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.033	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	7719.488	0.000	0.000

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/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: *Gadsby Peakers* (d)	Plant Name: *Currant Creek* (e)	Plant Name: *Lake Side* (f)	Line No.
Gas Turbine	Combined Cycle	Combined Cycle	1
Outdoor	Outdoor	Outdoor	2
2002	2005	2007	3
2002	2006	2007	4
181.05	566.90	591.30	5
127	549	536	6
1431	5643	8617	7
0	0	0	8
119	524	546	9
0	0	0	10
0	20	34	11
57257000	1474686000	2730622000	12
0	3403277	14532275	13
4272431	44164698	35510494	14
78335474	307118103	337551191	15
0	134848	0	16
82607905	354820926	387593960	17
456.2712	625.8969	655.4946	18
0	79526	54427	19
3612894	39605139	68694671	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
1134849	1814398	2560342	25
0	704055	552464	26
0	0	0	27
0	0	0	28
0	0	0	29
235107	782767	850616	30
0	0	0	31
565744	2042672	779374	32
243964	64506	23137	33
5792558	45093063	73515031	34
0.1012	0.0306	0.0269	35

(d)			(e)			(f)			Line No.
Gas			Gas			Gas			36
MCF			MCF			MCF			37
741317	0	0	10894332	0	0	19219074	0	0	38
1047	0	0	1037	0	0	1039	0	0	39
4.874	0.000	0.000	3.635	0.000	0.000	3.574	0.000	0.000	40
4.874	0.000	0.000	3.635	0.000	0.000	3.574	0.000	0.000	41
4.653	0.000	0.000	3.504	0.000	0.000	3.440	0.000	0.000	42
0.063	0.000	0.000	0.027	0.000	0.000	0.025	0.000	0.000	43
13561.573	0.000	0.000	7664.177	0.000	0.000	7312.230	0.000	0.000	44

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

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

Line No.	Item (a)	Plant Name: *Lake Side 2* (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Combined Cycle	
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor	
3	Year Originally Constructed	2014	
4	Year Last Unit was Installed	2014	
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	655.20	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	632	0
7	Plant Hours Connected to Load	8509	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	631	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	2995420000	0
13	Cost of Plant: Land and Land Rights	16794626	0
14	Structures and Improvements	53126468	0
15	Equipment Costs	569041382	0
16	Asset Retirement Costs	0	0
17	Total Cost	638962476	0
18	Cost per KW of Installed Capacity (line 17/5) Including	975.2175	0
19	Production Expenses: Oper, Supv, & Engr	62897	0
20	Fuel	71841194	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	3116374	0
26	Misc Steam (or Nuclear) Power Expenses	654939	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	923420	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	527160	0
33	Maintenance of Misc Steam (or Nuclear) Plant	23730	0
34	Total Production Expenses	77149714	0
35	Expenses per Net KWh	0.0258	0.0000

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
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	20181469	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1039	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.560	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	3.560	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.426	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.024	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	7000.074	0.000	0.000	0.000	0.000	0.000

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

The Cholla Plant is operated by Arizona Public Service Company and is jointly owned. PacifiCorp owns 100% of Unit No. 4 and 49.53% of common facilities. Data reported on page 402 represents PacifiCorp's share.

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

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 on page 402 represents PacifiCorp's share.

Schedule Page: 403 Line No.: -1 Column: d

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 reported on page 403 represents PacifiCorp's share.

Schedule Page: 403 Line No.: -1 Column: f

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 on page 403 represents PacifiCorp's share.

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

PacifiCorp does not have employees at the Cholla Plant.

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

PacifiCorp does not have employees at the Colstrip Plant.

Schedule Page: 403 Line No.: 11 Column: d

PacifiCorp does not have employees at the Craig Plant.

Schedule Page: 403 Line No.: 11 Column: f

PacifiCorp does not have employees at the Hayden Plant.

Schedule Page: 403 Line No.: 20 Column: d

Amount includes intercompany profits.

Schedule Page: 402.1 Line No.: -1 Column: b

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 on page 402.1 represents PacifiCorp's share. Costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this unit for calendar year 2016 were $1.3 million and were primarily credited to Account 506, Miscellaneous steam power expenses.

Schedule Page: 402.1 Line No.: -1 Column: c

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 on page 402.1 represents PacifiCorp's share. Costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this unit for calendar year 2016 were $7.6 million and were primarily credited to Account 506, Miscellaneous steam power expenses.

Schedule Page: 403.1 Line No.: -1 Column: e

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

Refer to Hunter - Total Plant on page 403.1 for the average number of employees.

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: 402.2 Line No.: -1 Column: b

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 on page 402.2 represents PacifiCorp's share. Costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this plant for calendar year

2016 were $27.6 million and were primarily credited to Account 506, Miscellaneous steam power expenses.

Schedule Page: 402.2 Line No.: -1 Column: c

PacifiCorp currently plans to remove Naughton Unit No. 3 (280 MW) from coal-fueled service by year-end 2018. The state of Wyoming approved the unit to operate as a coal-fueled unit until no later than January 30, 2019, and then either close or be converted to natural gas no later than June 30, 2019.

Schedule Page: 403.2 Line No.: -1 Column: d

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 reported on page 403.2 represents PacifiCorp's share. Costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this plant for calendar year 2016 were $5.1 million and were primarily credited to Account 506, Miscellaneous steam power expenses.

Schedule Page: 403.2 Line No.: -1 Column: f

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 on page 403.2 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: 403.2 Line No.: 11 Column: f

PacifiCorp does not have employees at the Hermiston Plant.

Schedule Page: 402.2 Line No.: 20 Column: b

Amount includes intercompany profits.

Schedule Page: 402.3 Line No.: -1 Column: b

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.: 11 Column: d

Refer to the Gadsby Steam Plant on page 403.2 for the average number of employees.

Schedule Page: 402.4 Line No.: 11 Column: b

Refer to the Lake Side Plant on page 403.3 for the average number of employees.

Schedule Page: 402 Line No.: 36 Column: b2

Cholla - Fuel oil is used for start-up purposes.

Schedule Page: 402 Line No.: 36 Column: c2

Colstrip - Fuel oil is used for start-up purposes.

Schedule Page: 402 Line No.: 36 Column: d2

Craig - Fuel oil is used for start-up purposes.

Schedule Page: 402 Line No.: 36 Column: e2

Dave Johnston - Fuel oil is used for start-up purposes.

Schedule Page: 402 Line No.: 36 Column: f2

Hayden - Fuel oil is used for start-up purposes.

Schedule Page: 402.1 Line No.: 36 Column: b2

Hunter Unit No. 1 - Fuel oil is used for start-up purposes.

Schedule Page: 402.1 Line No.: 36 Column: c2

Hunter Unit No. 2 - Fuel oil is used for start-up purposes.

Schedule Page: 402.1 Line No.: 36 Column: d2

Hunter Unit No. 3 - Fuel oil is used for start-up purposes.

Schedule Page: 402.1 Line No.: 36 Column: e2

Hunter - Total Plant - Fuel oil is used for start-up purposes.

Schedule Page: 402.1 Line No.: 36 Column: f2

Huntington - Fuel oil is used for start-up purposes.

Schedule Page: 402.2 Line No.: 36 Column: b2

Jim Bridger - Fuel oil is used for start-up purposes.

Schedule Page: 402.2 Line No.: 36 Column: c2

Naughton - Natural gas is used for start-up purposes.

Schedule Page: 402.2 Line No.: 36 Column: d2

Wyodak - Fuel oil is used for start-up purposes.

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/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)	26	32
7	Plant Hours Connect to Load	7,136	7,156
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	80,964,000	104,792,000
13	Cost of Plant		
14	Land and Land Rights	107,019	20,914
15	Structures and Improvements	1,698,921	2,340,917
16	Reservoirs, Dams, and Waterways	2,935,836	2,953,166
17	Equipment Costs	5,358,060	10,442,760
18	Roads, Railroads, and Bridges	133,348	479,588
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	10,233,184	16,237,345
21	Cost per KW of Installed Capacity (line 20 / 5)	511.6592	601.3831
22	Production Expenses		
23	Operation Supervision and Engineering	29,572	41,134
24	Water for Power	0	0
25	Hydraulic Expenses	25,366	34,245
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	1,254,452	1,560,385
28	Rents	30,813	41,597
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	5,332	25,379
31	Maintenance of Reservoirs, Dams, and Waterways	207,498	24,869
32	Maintenance of Electric Plant	91,481	108,125
33	Maintenance of Misc Hydraulic Plant	20,220	26,257
34	Total Production Expenses (total 23 thru 33)	1,664,734	1,861,991
35	Expenses per net KWh	0.0206	0.0178

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/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
8	19	30	6
8,770	8,363	6,436	7
			8
18	31	29	9
18	31	29	10
1	1	3	11
40,459,000	45,439,000	64,221,000	12
			13
0	0	3,511,105	14
1,502,236	2,373,755	3,985,318	15
5,183,909	14,779,679	9,177,687	16
1,337,839	2,155,970	14,698,356	17
50,817	250,151	572,059	18
0	0	0	19
8,074,801	19,559,555	31,944,525	20
538.3201	752.2906	1,064.8175	21
			22
23,562	44,326	141,833	23
700	1,213	0	24
42,368	73,439	113,412	25
0	0	0	26
255,058	376,661	1,224,554	27
56,629	98,156	20,286	28
0	0	0	29
23,982	50,817	13	30
13,831	41,569	33,001	31
13,737	103,015	26,634	32
35,812	62,238	326,270	33
465,679	851,434	1,886,003	34
0.0115	0.0187	0.0294	35

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HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 1927 Plant Name: Fish Creek (b)	FERC Licensed Project No. 20 Plant Name: Grace (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1952	1908
4	Year Last Unit was Installed	1952	1923
5	Total installed cap (Gen name plate Rating in MW)	11.00	33.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	10	29
7	Plant Hours Connect to Load	4,525	7,883
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	34,839,000	78,074,000
13	Cost of Plant		
14	Land and Land Rights	0	62,169
15	Structures and Improvements	1,757,824	2,085,484
16	Reservoirs, Dams, and Waterways	12,368,032	11,336,864
17	Equipment Costs	2,948,919	5,002,425
18	Roads, Railroads, and Bridges	533,015	335,165
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	17,607,790	18,822,107
21	Cost per KW of Installed Capacity (line 20 / 5)	1,600.7082	570.3669
22	Production Expenses		
23	Operation Supervision and Engineering	26,268	119,767
24	Water for Power	513	0
25	Hydraulic Expenses	31,070	41,560
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	237,567	1,308,135
28	Rents	41,528	12,321
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	27,957	16,515
31	Maintenance of Reservoirs, Dams, and Waterways	62,948	146,804
32	Maintenance of Electric Plant	47,873	64,424
33	Maintenance of Misc Hydraulic Plant	28,695	114,945
34	Total Production Expenses (total 23 thru 33)	504,419	1,824,471
35	Expenses per net KWh	0.0145	0.0234

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/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
18	86	28	6
8,332	5,949	8,276	7
			8
19	83	32	9
19	83	32	10
1	2	1	11
100,752,000	214,776,000	134,067,000	12
			13
341,706	25,845	0	14
7,842,418	3,675,180	2,931,094	15
15,308,188	15,655,267	15,717,070	16
3,035,214	15,370,749	6,717,856	17
1,095,742	886,710	488,877	18
0	0	0	19
27,623,268	35,613,751	25,854,897	20
1,534.6260	363.4798	808.2181	21
			22
1,551,839	215,039	51,866	23
0	0	1,492	24
23,633	10,328	90,358	25
0	0	0	26
1,060,957	605,023	493,150	27
27,731	46,573	120,770	28
0	0	0	29
3,923	26,379	59,756	30
15,200	28,145	55,659	31
131,212	69,187	115,530	32
18,290	53,310	79,175	33
2,832,785	1,053,984	1,067,756	34
0.0281	0.0049	0.0080	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 2016/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)	34	143
7	Plant Hours Connect to Load	6,831	8,784
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	146,665,000	560,116,000
13	Cost of Plant		
14	Land and Land Rights	0	988,614
15	Structures and Improvements	6,198,165	105,535,586
16	Reservoirs, Dams, and Waterways	32,523,973	30,135,690
17	Equipment Costs	11,839,981	18,212,123
18	Roads, Railroads, and Bridges	1,820,580	3,958,128
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	52,382,699	158,830,141
21	Cost per KW of Installed Capacity (line 20 / 5)	1,360.5896	1,167.8687
22	Production Expenses		
23	Operation Supervision and Engineering	61,515	1,504,076
24	Water for Power	1,795	6,354
25	Hydraulic Expenses	108,745	792,916
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	631,228	466,962
28	Rents	145,347	89,475
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	77,338	55,771
31	Maintenance of Reservoirs, Dams, and Waterways	283,946	168,377
32	Maintenance of Electric Plant	95,190	102,972
33	Maintenance of Misc Hydraulic Plant	92,807	342,889
34	Total Production Expenses (total 23 thru 33)	1,497,911	3,529,792
35	Expenses per net KWh	0.0102	0.0063

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 2016/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
44	14	36	6
8,778	8,739	8,780	7
			8
45	28	36	9
45	28	36	10
1	2	1	11
232,820,000	39,854,000	239,892,000	12
			13
0	283,870	105,168	14
4,124,365	1,893,716	3,541,996	15
12,843,068	6,316,949	33,191,505	16
5,556,855	6,473,188	7,057,063	17
264,441	503,332	325,034	18
0	0	0	19
22,788,729	15,471,055	44,220,766	20
536.2054	515.7018	1,381.8989	21
			22
67,093	108,696	304,284	23
1,982	0	8,113	24
120,047	37,782	3,434	25
0	0	0	26
699,147	658,157	493,591	27
160,515	10,746	38,440	28
0	0	274	29
69,090	4,839	94,029	30
15,348	1,371	279,162	31
196,230	131,803	116,196	32
102,006	65,963	244,289	33
1,431,458	1,019,357	1,581,812	34
0.0061	0.0256	0.0066	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 2016/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	9
7	Plant Hours Connect to Load	8,750	7,243
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	75,625,000	17,769,000
13	Cost of Plant		
14	Land and Land Rights	0	511,083
15	Structures and Improvements	2,203,571	730,462
16	Reservoirs, Dams, and Waterways	14,877,385	10,596,080
17	Equipment Costs	8,967,103	5,424,548
18	Roads, Railroads, and Bridges	599,269	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	26,647,328	17,262,173
21	Cost per KW of Installed Capacity (line 20 / 5)	1,480.4071	1,194.6140
22	Production Expenses		
23	Operation Supervision and Engineering	34,426	50,725
24	Water for Power	839	0
25	Hydraulic Expenses	50,842	17,631
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	279,624	406,108
28	Rents	67,954	5,093
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	31,097	35
31	Maintenance of Reservoirs, Dams, and Waterways	3,815	678
32	Maintenance of Electric Plant	21,287	57,164
33	Maintenance of Misc Hydraulic Plant	46,383	20,081
34	Total Production Expenses (total 23 thru 33)	536,267	557,515
35	Expenses per net KWh	0.0071	0.0314

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 2016/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	251	166	6
8,719	6,575	6,781	7
			8
12	264	164	9
12	264	164	10
2	1	1	11
61,093,000	761,595,000	645,247,000	12
			13
0	14,160,894	8,363,013	14
4,238,679	72,443,760	16,284,524	15
89,513,753	47,054,071	32,328,233	16
2,631,607	24,720,736	16,623,858	17
2,089,012	1,133,091	2,036,648	18
0	0	0	19
98,473,051	159,512,552	75,636,276	20
8,952.0955	664.6356	564.4498	21
			22
17,279	2,530,560	1,390,629	23
513	11,212	6,260	24
272,745	1,657,547	781,255	25
0	0	0	26
317,094	282,744	353,834	27
41,528	157,897	88,159	28
0	0	0	29
15,777	40,308	36,481	30
55,661	306,251	171,804	31
13,497	216,802	184,091	32
26,263	580,305	330,256	33
760,357	5,783,626	3,342,769	34
0.0124	0.0076	0.0052	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

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 2016/Q4

GENERATING PLANT STATISTICS (Small Plants)

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

Line No.	Name of Plant (a)		Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Hydroelectric :	Licensed Proj. No.					
2	Ashton	2381	1917	6.70	7.0	28,779,000	33,880,397
3	Bend		1913	1.11	1.0	1,958,000	1,970,034
4	Big Fork	2652	1910	4.15	4.6	29,483,000	7,592,405
5	Eagle Point		1957	2.81	2.8	18,526,000	1,948,844
6	East Side	2082	1924	3.20			1,991,695
7	Fall Creek	2082	1903	2.20	2.0	10,146,000	1,429,457
8	Granite		1896	2.00	1.3	6,219,000	5,238,188
9	Gunlock		1917	0.75	0.5	856,000	683,045
10	Last Chance		1983	1.73	0.4	1,162,000	2,804,629
11	Paris		1910	0.72	0.7	2,417,000	448,946
12	Pioneer	2722	1897	5.00	3.4	11,369,000	11,442,469
13	Prospect No. 1	2630	1912	3.76			2,590,660
14	Prospect No. 3	2337	1932	7.20	7.7	32,997,000	8,896,843
15	Prospect No. 4	2630	1944	1.00			2,409,792
16	Sand Cove		1926	0.80	0.5	702,000	939,202
17	Stairs	597	1895	1.00	1.0	4,544,000	1,721,738
18	Veyo		1920	0.50	0.2	249,000	897,784
19	Viva Naughton		1986	0.74	0.2	641,000	1,232,115
20	Wallowa Falls	308	1921	1.10	1.1	4,340,000	3,277,317
21	Weber	1744	1911	3.85	2.0	13,611,000	3,638,149
22	West Side	2082	1908	0.60	0.6	-16,000	468,574
23	Keno Regulating Dam	2082					7,519,318
24	Upper Klamath Lake	2082					3,847,587
25	North Umpqua	1927					16,329,447
26							
27	Pumping Plant:						
28	Lifton		1917	-2.80	-1.0	-3,617,000	19,494,606
29							
30	Wind:						
31	Dunlap Ranch 1		2010	111.00	111.0	388,498,000	240,971,645
32	Foote Creek		1999	32.15	32.2	108,681,000	38,389,266
33	Glenrock		2008	99.00	99.0	311,607,000	203,182,790
34	Glenrock III		2009	39.00	39.0	118,738,000	88,428,982
35	Rolling Hills		2009	99.00	99.0	284,156,000	205,070,761
36	Goodnoe Hills		2008	94.00	93.0	223,899,000	184,559,901
37	Leaning Juniper 1		2006	100.00	100.5	202,605,000	179,176,332
38	Marengo		2007	140.40	136.0	356,053,000	242,241,585
39	Marengo II		2008	70.20	69.0	170,369,000	130,052,284
40	Seven Mile Hill		2008	99.00	99.0	348,841,000	202,089,671
41	Seven Mile Hill II		2008	19.50	19.5	69,847,000	42,464,872
42	High Plains		2009	99.00	99.0	316,175,000	220,356,669
43	McFadden Ridge I		2009	28.50	28.5	95,925,000	57,089,361
44							
45	Solar:						
46	Black Cap		2012	2.00	2.0	4,021,000	74,380

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
5,056,776	517,860		143,982	Water		2
1,774,805	64,572		24,622	Water		3
1,829,495	399,815		112,559	Water		4
693,539	298,431		114,279	Water		5
622,405	36,370		2,306	Water		6
649,753	149,315		65,543	Water		7
2,619,094	200,589		13,558	Water		8
910,727	31,480		75,639	Water		9
1,621,173	118,865		9,507	Water		10
623,536	75,834		17,920	Water		11
2,288,494	534,144		154,215	Water		12
689,005	112,936		1,991,650	Water		13
1,235,673	285,054		240,168	Water		14
2,409,792	28,160		19,185	Water		15
1,174,003	69,930		34,745	Water		16
1,721,738	182,004		14,050	Water		17
1,795,568	35,324		220,279	Water		18
1,665,020	144,352		203,044	Water		19
2,979,379	118,302		28,945	Water		20
944,974	335,076		24,994	Water		21
780,957	5,213		1,851	Water		22
	24,738		1,595			23
	249,116		46,832			24
						25
						26
						27
-6,962,359	242,951		64,580	Water		28
						29
						30
2,170,916	242,442		1,197,451	Wind		31
1,194,067	452,885		1,300,724	Wind		32
2,052,351	221,362		1,371,291	Wind		33
2,267,410	89,729		403,639	Wind		34
2,071,422	173,853		1,021,585	Wind		35
1,963,403	593,516		1,630,110	Wind		36
1,791,763	728,462		1,171,752	Wind		37
1,725,367	1,180,562		1,383,131	Wind		38
1,852,597	603,480		688,622	Wind		39
2,041,310	513,885		1,218,502	Wind		40
2,177,686	109,628		240,008	Wind		41
2,225,825	925,000		1,267,002	Wind		42
2,003,135	264,349		417,123	Wind		43
						44
						45
37,190	498,523			Solar		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.: 22 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.: 23 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.: 24 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.: 25 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.: 28 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.: 30 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.: 32 Column: a

Foote Creek

The Foote Creek wind-powered generating facility is operated by PacifiCorp 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 32 represents PacifiCorp's share.

Schedule Page: 410 Line No.: 46 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 2016/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	500kV costs and expenses							
14								
15	Subtotal 500kV					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	16,964.00	654.00	284

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 2016/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)	
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	233,448,416	246,788,115		1,701,963	295,737	1,997,700	13
								14
	13,339,699	233,448,416	246,788,115		1,701,963	295,737	1,997,700	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
	234,140,526	3,437,321,298	3,671,461,824	523,824	17,542,520	2,406,374	20,472,718	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 2016/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	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	82.00		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 345kV					2,755.00	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	ARROWHEAD, WY	FIREHOLE, WY	230.00	230.00	Wood - H	9.00		1
31	ATLANTIC CITY, WY	COLUMBIA GENEVA, WY	230.00	230.00	Wood - H	1.00		1
32	BEN LOMOND, UT	NAUGHTON #1, WY	230.00	230.00	Wood - H	88.00		1
33	BEN LOMOND, UT	NAUGHTON #2, WY	230.00	230.00	Wood - H	88.00		1
34	BIRCH CREEK, UT	RAILROAD, WY	230.00	230.00	Wood - H	19.00		1
35	BITTER CREEK, WY	MONELL, WY	230.00	230.00	Wood - H	3.00		1
36					TOTAL	16,964.00	654.00	284

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
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 54/7								18
1272 ACSR 36/1								19
1272 ACSR 45/7								20
1272 ACSR 45/7								21
1272 ACSR 45/7								22
	152,505,245	1,656,245,596	1,808,750,841	213,156	1,466,262	718,689	2,398,107	23
								24
	152,505,245	1,656,245,596	1,808,750,841	213,156	1,466,262	718,689	2,398,107	25
								26
1272 ACSR 36/1								27
1272 ACSR 45/7								28
795 ACSR 45/7								29
795 ACSR 26/7								30
1272 ACSR 36/1								31
795 ACSR 26/7								32
795 ACSR 26/7								33
954 ACSR 54/7								34
795 ACSR 26/7								35
	234,140,526	3,437,321,298	3,671,461,824	523,824	17,542,520	2,406,374	20,472,718	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 2016/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.
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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	BRIDGER PUMP, WY	MANS FACE, WY	230.00	230.00	Wood - H	1.00		1
2	BUFFALO, WY	CASPER, WY	230.00	230.00	Wood - H	107.00		1
3	CASPER, WY	DAVE JOHNSTON, WY	230.00	230.00	Wood - H	36.00		1
4	CASPER, WY	RIVERTON, WY	230.00	230.00	Wood - H	110.00		1
5	CHAPPEL CREEK, WY	CRAVEN CREEK, WY	230.00	230.00	Steel - SP	30.00		1
6	CHAPPEL CREEK, WY	JONAH GAS, WY	230.00	230.00	Wood - H	32.00		1
7	CHAPPEL CREEK, WY	RILEY RIDGE, WY	230.00	230.00	Wood - H	29.00	6.00	1
8	CRAVEN CREEK, WY	PIONEER, WY	230.00	230.00	Wood - H	2.00		1
9	DAVE JOHNSTON, WY	SPENCE, WY	230.00	230.00	Wood - H	31.00		1
10	DAVE JOHNSTON, WY	WYODAK, WY	230.00	230.00	Wood - H	69.00		1
11	DIXONVILLE 500kV, OR	DIXONVILLE 230kV, OR	230.00	230.00	Wood - H	1.00		1
12	DIXONVILLE, OR	RESTON (BPA), OR	230.00	230.00	Wood - H	17.00		1
13	FAIRVIEW (BPA), OR	ISTHMUS, OR	230.00	230.00	Wood - H	12.00		1
14	FIREHOLE, WY	MONUMENT, WY	230.00	230.00	Wood - H	49.00		1
15	FRY, OR	BETHEL, OR	230.00	230.00	Wood - H	26.00		1
16	FRY, OR	ALVEY, OR	230.00	230.00	Wood - H	45.00		1
17	GLEN CANYON, AZ	SIGURD, UT	230.00	230.00	Wood - H	159.00		1
18	GONDER, UT - NV STATE	PAVANT, UT	230.00	230.00	Wood - H	98.00		1
19	BUFFALO, WY	SHERIDAN (MDU), WY	230.00	230.00	Wood - H	40.00		1
20	DIXONVILLE, OR	GRANTS PASS, OR	230.00	230.00	Wood - H	62.00		1
21	HURRICANE, OR	WALLA WALLA, WA	230.00	230.00	Wood - H	78.00		1
22	POINT OF ROCKS, WY	DAVE JOHNSTON, WY	230.00	230.00	Wood - H	209.00		1
23	JIM BRIDGER, WY	SPENCE, WY	230.00	230.00	Wood - H	149.00		1
24	KLAMATH FALLS, OR	MALIN, OR	230.00	230.00	Wood - H	35.00		1
25	LIMA, WY	ROBERSON, WY	230.00	230.00	Wood - H	2.00		1
26	LONE PINE, OR	KLAMATH FALLS, OR	230.00	230.00	Wood - H	76.00		1
27	LONE PINE, OR	MERIDIAN #1, OR	230.00	230.00	Steel - SP	5.00		1
28	LONE PINE, OR	MERIDIAN #2, OR	230.00	230.00	Steel - SP	5.00		1
29	MCNARY (BPA), WA	WALLA WALLA, WA	230.00	230.00	Wood - H	56.00		1
30	MERIDIAN, OR	GRANTS PASS, OR	230.00	230.00	Wood - H	35.00		1
31	HIGH PLAINS, WY	STANDPIPE, WY	230.00	230.00	Wood - H	38.00		1
32	MONUMENT, WY	EXXON, WY	230.00	230.00	Wood - H	13.00		1
33	MONUMENT, WY	CRAVEN CREEK, WY	230.00	230.00	Wood - H	20.00		1
34	NAUGHTON, WY	TREASURETON, ID	230.00	230.00	Wood - H	80.00		1
35	NAUGHTON, WY	MONUMENT, WY	230.00	230.00	Wood - H	30.00		1
36					TOTAL	16,964.00	654.00	284

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 2016/Q4

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272 ACSR 36/1								1
1272 ACSR 36/1								2
								3
1272 ACSR 36/1								4
954 ACSR 54/7								5
1272 ACSR 45/7								6
1272 ACSR 45/7								7
1272 ACSR 45/7								8
1272 ACSR 45/7								9
1272 ACSR 36/1								10
1272 ACSR 36/1								11
795 ACSR 26/7								12
1272 ACSR 36/1								13
1272 ACSR 45/7								14
1272 ACSR 36/1								15
1272 ACSR 36/1								16
954 ACSR 45/7								17
795 ACSR 45/7								18
795 ACSR 26/7								19
1272 ACSR 36/1								20
1272 ACSR 36/1								21
1272 ACSR 36/1								22
1272 ACSR 36/1								23
1272 ACSR 36/1								24
1272 ACSR 45/7								25
795 ACSR 26/7								26
1272 ACSR 54/19								27
1272 ACSR 36/1								28
1272 ACSR 36/1								29
1272 ACSR 36/1								30
1272 ACSR 45/7								31
1272 ACSR 36/1								32
1272 ACSR 45/7								33
1272 ACSR 45/7								34
1272 ACSR 36/1								35
	234,140,526	3,437,321,298	3,671,461,824	523,824	17,542,520	2,406,374	20,472,718	36

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

TRANSMISSION LINE STATISTICS

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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	NAUGHTON, WY	CRAVEN CREEK, WY	230.00	230.00	Wood - H	16.00		1
2	PALISADES SS, WY	BLUE RIM, WY	230.00	230.00	Wood - H	4.00		1
3	PAROWAN VALLEY, UT	SIGURD, UT	230.00	230.00	Wood - H	94.00		1
4	PAROWAN VALLEY, UT	WEST CEDAR, UT	230.00	230.00	Wood - H	26.00		1
5	PAVANT, UT	SIGURD, UT	230.00	230.00	Wood - H	43.00		1
6	JIM BRIDGER, WY	ROCK SPRINGS, WY	230.00	230.00	Wood - H	35.00		1
7	POMONA, WA	UNION GAP, WA	230.00	230.00	Wood - H	8.00		1
8	RIVERTON, WY	ROCK SPRINGS, WY	230.00	230.00	Wood - H	118.00		1
9	RIVERTON, WY	THERMOPOLIS, WY	230.00	230.00	Wood - H	51.00		1
10	ROCK SPRINGS, WY	FLAMING GORGE, UT	230.00	230.00	Wood - H	55.00		1
11	ROCK SPRINGS, WY	JIM BRIDGER, WY	230.00	230.00	Wood - H	35.00		1
12	ROCK SPRINGS, WY	MONUMENT, WY	230.00	230.00	Wood - H	41.00		1
13	SHIRLEY BASIN, WY	DUNLAP RANCH, WY	230.00	230.00	Wood - H	12.00		1
14	SWIFT No. 1, WA	SWIFT No. 2, WA	230.00	230.00	Wood - H	2.00		1
15	SWIFT No. 2, WA	WOODLAND (BPA) SS, WA	230.00	230.00	Wood - H	23.00		1
16	TALBOT, WA	MARENGO II, WA	230.00	230.00	Wood - H	7.00		1
17	TAP TO HANNA, OR	NICKEL MOUNTAIN, OR	230.00	230.00	Wood - H	9.00		1
18	THERMOPOLIS, WY	YELLOWTAIL, MT	230.00	230.00	Wood - H	176.00		1
19	TREASURETON, ID	BRADY, ID	230.00	230.00	Wood - H	66.00		1
20	TROUTDALE (BPA), OR	GRESHAM (PGE), OR	230.00	230.00	Steel Tower	6.00		1
21	TROUTDALE (BPA), OR	LINNEMAN (PGE), OR	230.00	230.00			7.00	1
22	UNION GAP, WA	MIDWAY (BPA), WA	230.00	230.00	Wood - H	39.00		1
23	WALLA WALLA, WA	LEWISTON (AVISTA), ID	230.00	230.00	Wood - H	45.00		1
24	WALLA WALLA, WA	WANAPUM (GPUD), WA	230.00	230.00	Wood - H	33.00		1
25	WANAPUM (GPUD), WA	POMONA, WA	230.00	230.00	Wood - H	37.00		1
26	WINDSTAR, WY	GLENROCK, WY	230.00	230.00	Wood - H	13.00		1
27	WYODAK, WY	BUFFALO, WY	230.00	230.00	Wood - H	69.00		1
28	YAMSAY (BPA), OR	KLAMATH FALLS, OR	230.00	230.00	Wood - H	63.00		1
29	SHERIDAN (MDU), WY	YELLOWTAIL, MT	230.00	230.00	Wood - H	62.00		1
30	230kV costs and expenses							
31								
32	Subtotal 230kV					3,338.00	13.00	73
33								
34	BIG GRASSY, ID	JEFFERSON, ID	161.00	161.00	Wood - H		21.00	1
35	ANTELOPE, ID	GOSHEN, ID	161.00	161.00	Wood - H	45.00		1
36					TOTAL	16,964.00	654.00	284

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 2016/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954 ACSR 54/7								1
1272 ACSR 36/1								2
795 ACSR 45/7								3
795 ACSR 45/7								4
795 ACSR 45/7								5
1272 ACSR 45/7								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
1272 ACSR 36/1								12
795 ACSR 26/7								13
954 ACSR 45/7								14
954 ACSR 45/7								15
795 ACSR 26/7								16
795 ACSR 26/7								17
1272 ACSR 36/1								18
795 ACSR 26/7								19
954 ACSR 45/7								20
900 ACSR 54/7								21
954 ACSR 45/7								22
1272 ACSR 36/1								23
1272 ACSR 36/1								24
1272 ACSR 36/1								25
1272 ACSR 45/7								26
1272 ACSR 36/1								27
795 ACSR 26/7								28
795 ACSR 26/7								29
	19,453,961	389,392,423	408,846,384	30,060	3,400,325	431,233	3,861,618	30
								31
	19,453,961	389,392,423	408,846,384	30,060	3,400,325	431,233	3,861,618	32
								33
250HH CU /7								34
397.5 ACSR 26/7								35
	234,140,526	3,437,321,298	3,671,461,824	523,824	17,542,520	2,406,374	20,472,718	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 2016/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	BONNEVILLE, ID	EAGLEROCK, ID	161.00	161.00	Wood - SP	9.00		1
2	GOSHEN, ID	GRACE, ID	161.00	161.00	Wood - H	57.00		1
3	GOSHEN, ID	RIGBY, ID	161.00	161.00	Wood - H	31.00		1
4	GOSHEN, ID	SUGARMILL, ID	161.00	161.00	Wood - SP	17.00		1
5	SUGARMILL, ID	RIGBY, ID	161.00	161.00	Wood - SP	17.00		1
6	EAGLEROCK, ID	GOSHEN, ID	161.00	161.00	Wood - H	15.00		1
7	YELLOWTAIL, MT	RIMROCK, MT	161.00	161.00	Wood - H	46.00		1
8	RIGBY, ID	JEFFERSON, ID	161.00	161.00	Wood - SP	18.00		1
9	GOSHEN, ID	JEFFERSON, ID	161.00	161.00	Wood - H		30.00	1
10	161kV costs and expenses							
11								
12	Subtotal 161kV					255.00	51.00	11
13								
14	90TH SOUTH, UT	SANDY, UT	138.00	138.00	Steel - SP	1.00		1
15	90TH SOUTH, UT	DUMAS #1, UT	138.00	138.00	Wood - H	12.00		1
16	90TH SOUTH, UT	DUMAS #2, UT	138.00	138.00	Wood - H	6.00		1
17	90TH SOUTH, UT	OQUIRRH, UT	138.00	138.00	Wood - SP	10.00		1
18	ABAJO, UT	PINTO, UT	138.00	138.00	Wood - H	44.00		1
19	ABAJO, UT	RESOLUTE, UT	138.00	138.00	Wood - SP	10.00		1
20	AGRIUM, UT	THREEMILE KNOLL, ID	138.00	138.00	Wood - H	4.00		1
21	ANSCHTZ CO-GEN, WY	EVANSTON, WY	138.00	138.00	Wood - H	22.00		1
22	ANTELOPE, ID	SCOVILLE #1, ID	138.00	138.00	Wood - H	1.00		1
23	ANTELOPE, ID	SCOVILLE #2, ID	138.00	138.00	Wood - H	1.00		1
24	ASHGROVE, UT	CLOVER, UT	138.00	138.00	Wood - H	26.00		1
25	ASHLEY, UT	CARBON, UT	138.00	138.00	Wood - H	102.00		1
26	ASHLEY, UT	VERNAL, UT	138.00	138.00	Wood - H	12.00		1
27	BANGERTER, UT	OQUIRRH, UT	138.00	138.00	Wood - H		6.00	1
28	BDO, UT	BDO TAP, UT	138.00	138.00	Wood - SP	1.00		1
29	BEN LOMOND, UT	BRIGHAM CITY, UT	138.00	138.00	Wood - H	14.00		1
30	BEN LOMOND #1, UT	EL MONTE, UT	138.00	138.00	Steel - SP	14.00		1
31	BEN LOMOND #2, UT	EL MONTE, UT	138.00	138.00			13.00	1
32	BEN LOMOND, UT	HONEYVILLE, UT	138.00	138.00	Steel Tower	22.00		1
33	BEN LOMOND, UT	SYRACUSE #1, UT	138.00	230.00	Steel Tower	7.00	13.00	1
34	BEN LOMOND, UT	ANGEL, UT	138.00	138.00	Steel - SP	28.00		1
35	BEN LOMOND, UT	W ZIRCONIUM, UT	138.00	138.00	Wood - SP	14.00		1
36					TOTAL	16,964.00	654.00	284

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 2016/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
954 ACSR 45/7								1
250HH CU /7								2
397.5 ACSR 26/7								3
795 AAC /37								4
397.5 ACSR 26/7								5
1272 ACSR 45/7								6
556.5 ACSR 26/7								7
397.5 ACSR 26/7								8
250HH CU /7								9
	623,490	25,826,911	26,450,401		236,815	1,925	238,740	10
								11
	623,490	25,826,911	26,450,401		236,815	1,925	238,740	12
								13
795 AAC /37								14
795 AAC /37								15
795 AAC /37								16
795 ACSR 26/7								17
397.5 ACSR 26/7								18
795 ACSR 26/7								19
397.5 ACSR 26/7								20
795 ACSR 26/7								21
397.5 ACSR 26/7								22
397.5 ACSR 26/7								23
397.5 ACSR 26/7								24
397.5 ACSR 26/7								25
397.5 ACSR 26/7								26
								27
397.5 ACSR 26/7								28
1272 ACSR 45/7								29
795 ACSR 45/7								30
795 ACSR 45/7								31
250 CUHD /12								32
795 AAC /37								33
397.5 ACSR 26/7								34
795 AAC /37								35
	234,140,526	3,437,321,298	3,671,461,824	523,824	17,542,520	2,406,374	20,472,718	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 2016/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	BEN LOMOND, UT	WHEELON, UT	138.00	138.00	Steel Tower	42.00		1
2	BEN LOMOND, UT	SYRACUSE, UT	138.00	138.00	Steel Tower	25.00		1
3	BONANZA, UT	CHAPITA, UT	138.00	138.00	Wood - H	9.00		1
4	BRIDGERLAND, UT	GREEN CANYON, UT	138.00	138.00	Wood - SP	16.00		1
5	BRIGHAM CITY, UT	WHEELON, UT	138.00	138.00	Wood - H	24.00		1
6	BUTLERVILLE, UT	90TH SOUTH, UT	138.00	138.00	Steel - SP	9.00		1
7	CAMERON, UT	PAROWAN, UT	138.00	138.00	Wood - H	35.00		1
8	CAMERON, UT	SIGURD, UT	138.00	138.00	Wood - H	64.00		1
9	CANYON COMP, WY	STR 204, WY	138.00	138.00	Wood - H	12.00		1
10	CARBON, UT	HELPER #2, UT	138.00	138.00	Wood - H	2.00		1
11	CARBON, UT	SPANISH FORK #1, UT	138.00	138.00	Steel Tower	54.00		1
12	CARBON, UT	SPANISH FORK #2, UT	138.00	138.00	Steel Tower	52.00		1
13	CARBON, UT	MOAB, UT	138.00	138.00	Wood - H	120.00		1
14	CLEAR CREEK, WY	PAINTER, UT	138.00	138.00	Wood - SP	5.00		1
15	CLOVER, UT	NEBO, UT	138.00	138.00	Wood - SP	8.00		1
16	COLUMBIA, UT	SUNNYSIDE, UT	138.00	138.00	Wood - H	2.00		1
17	COTTONWOOD, UT	MCCLELLAND, UT	138.00	138.00	Steel - SP	6.00		1
18	COTTONWOOD, UT	HAMMER, UT	138.00	138.00	Wood - SP	5.00		1
19	COTTONWOOD, UT	SILVER CREEK, UT	138.00	138.00	Wood - SP	29.00		1
20	CUTLER, UT	WHEELON, UT	138.00	138.00	Wood - SP	1.00		1
21	DRY CREEK, UT	SPANISH FORK, UT	138.00	138.00	Steel - SP	5.00		1
22	DUMAS, UT	WESTFIELD, UT	138.00	138.00	Wood - SP	18.00		1
23	DYNAMO, UT	TRI-CITY #1, UT	138.00	138.00	Steel - SP	2.00		1
24	DYNAMO, UT	TRI-CITY #2, UT	138.00	138.00			3.00	1
25	EAST LAYTON, UT	105 TAP, UT	138.00	138.00	Steel - SP	15.00		1
26	EBAY TAP, UT	OQUIRRH, UT	138.00	138.00	Wood - SP	1.00		1
27	EL MONTE, UT	STR 30B, UT	138.00	138.00	Steel - SP	4.00		1
28	EL MONTE, UT	PIONEER, UT	138.00	138.00	Steel - SP	1.00		1
29	EVANSTON, WY	RAILROAD, UT	138.00	138.00	Wood - SP	3.00		1
30	FRANKLIN, ID	TREASURETON, ID	138.00	138.00	Wood - SP	10.00		1
31	FRANKLIN, ID	GREEN CANYON, UT	138.00	138.00	Wood - SP	25.00		1
32	GADSBY, UT	THIRD WEST, UT	138.00	138.00	Wood - SP	1.00		1
33	GADSBY, UT	TERMINAL, UT	138.00	138.00	Wood - SP	6.00		1
34	GADSBY, UT	JORDAN, UT	138.00	138.00	Wood - SP	1.00		1
35	GREEN CANYON, UT	NIBLEY, UT	138.00	138.00	Wood - SP	7.00		1
36					TOTAL	16,964.00	654.00	284

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TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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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)			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)	
250 CUHD /12								1
1272 ACSR 45/7								2
795 ACSR 26/7								3
1272 ACSR 45/7								4
795 ACSR 26/7								5
795 AAC /37								6
397.5 ACSR 26/7								7
397.5 ACSR 26/7								8
795 ACSR 26/7								9
556.5 ACSR 26/7								10
795 ACSR 26/7								11
1272 ACSR 45/7								12
954 ACSR 54/7								13
795 ACSR 26/7								14
1272 ACSR 45/7								15
397.5 ACSR 26/7								16
795 AAC /37								17
795 AAC /37								18
397.5 ACSR 26/7								19
250 CUHD /12								20
1272 ACSR 45/7								21
795 ACSR 26/7								22
795 ACSR 26/7								23
795 ACSR 26/7								24
795 ACSR 26/7								25
795 ACSR 26/7								26
1272 ACSR 45/7								27
1272 ACSR 45/7								28
795 ACSR 26/7								29
795 ACSR 26/7								30
397.5 ACSR 26/7								31
1272 AAC /61								32
1272 ACSR 45/7								33
1272 ACSR 45/7								34
1272 ACSR 45/7								35
	234,140,526	3,437,321,298	3,671,461,824	523,824	17,542,520	2,406,374	20,472,718	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 2016/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	GREEN CANYON, UT	WHEELON, UT	138.00	138.00	Wood - SP	19.00		1
2	HALE, UT	MIDWAY, UT	138.00	138.00	Wood - H	19.00		1
3	HALE, UT	TANNER, UT	138.00	138.00	Wood - H	7.00		1
4	HALE, UT	SPANISH FORK, UT	138.00	138.00	Wood - H	18.00		1
5	HAMMER, UT	BUTLERVILLE, UT	138.00	138.00			2.00	1
6	HONEYVILLE, UT	LAMPO, UT	138.00	138.00	Wood - H	25.00		1
7	HONEYVILLE, UT	WHEELON, UT	138.00	138.00			14.00	1
8	HUNTINGTON, UT	MCFADDEN, UT	138.00	138.00	Wood - H	7.00		1
9	JERUSALEM, UT	NEBO, UT	138.00	138.00	Wood - H	26.00		1
10	JORDAN, UT	THIRDWEST, UT	138.00	138.00	Wood - SP	1.00		1
11	JORDAN, UT	MCCLELLAND, UT	138.00	138.00	Wood - SP	5.00		1
12	JORDAN, UT	TERMINAL, UT	138.00	138.00	Wood - SP	6.00		1
13	BARNEYS, UT	GRINDING, UT	138.00	138.00	Wood - SP	1.00		1
14	KEARNS, UT	TAYLORSVILLE, UT	138.00	138.00	Wood - SP	3.00		1
15	KEARNS, UT	WEST VALLEY, UT	138.00	138.00	Wood - SP	2.00		1
16	LONE PEAK, UT	CAMP WILLIAMS, UT	138.00	138.00			8.00	1
17	MCCLELLAND, UT	MID VALLEY, UT	138.00	138.00	Wood - SP	6.00		1
18	MCFADDEN, UT	BLACKHAWK, UT	138.00	138.00	Wood - H	11.00		1
19	MID VALLEY, UT	TAYLORSVILLE, UT	138.00	138.00	Wood - SP	4.00	2.00	1
20	MID VALLEY #2, UT	COTTONWOOD, UT	138.00	138.00	Wood - SP	5.00		1
21	MID VALLEY #1, UT	COTTONWOOD, UT	138.00	138.00	Wood - SP	3.00		1
22	MID VALLEY, UT	90TH SOUTH, UT	138.00	138.00	Wood - H	9.00		1
23	MIDDLETON, UT	ST GEORGE, UT	138.00	138.00	Wood - H	1.00		1
24	MOAB, UT	PINTO, UT	138.00	138.00	Wood - H	68.00		1
25	NAUGHTON, WY	CANYON COMP, WY	138.00	138.00	Wood - H	36.00		1
26	NAUGHTON, WY	PAINTER, WY	138.00	138.00	Wood - H	48.00		1
27	NEBO, UT	DRY CREEK, UT	138.00	138.00	Wood - H	33.00		1
28	NUCOR STEEL, UT	WHEELON, UT	138.00	138.00	Wood - H	10.00		1
29	ONEIDA, ID	OVID, UT	138.00	138.00	Wood - H	23.00		1
30	ONIEDA, ID	GRACE, ID	138.00	138.00	Wood - H	19.00		1
31	GRINDING, UT	OQUIRRH, UT	138.00	138.00	Wood - SP	7.00		1
32	GRINDING, UT	TOOELE, UT	138.00	138.00	Wood - SP	14.00		1
33	OQUIRRH, UT	TOOELE, UT	138.00	138.00	Steel - SP	23.00		1
34	OQUIRRH, UT	BARNEY, UT	138.00	138.00	Wood - H	5.00		1
35	OQUIRRH, UT	BINGHAM CANYON, UT	138.00	138.00	Wood - H	8.00		1
36					TOTAL	16,964.00	654.00	284

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 2016/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
397.5 ACSR 26/7								1
397.5 ACSR 26/7								2
1272 ACSR 45/7								3
1272 ACSR 45/7								4
795 ACSR 26/7								5
397.5 ACSR 26/7								6
250 CUHD /12								7
397.5 ACSR 26/7								8
397.5 ACSR 26/7								9
1272 AAC /61								10
795 AAC /37								11
1272 AAC /91								12
1272 AAC /61								13
795 ACSR 26/7								14
								15
1272 ACSR 45/7								16
795 AAC 26/7								17
795 AAC 26/7								18
1272 ACSR /61								19
								20
								21
1272 ACSR 45/7								22
397.5 ACSR 26/7								23
397.5 ACSR 26/7								24
795 AAC 26/7								25
795 AAC 26/7								26
795 AAC 26/7								27
397.5 ACSR 26/7								28
336.4 ACSR 26/7								29
250 CUHD /12								30
795 ACSR 45/7								31
795 ACSR 45/7								32
1272 ACSR 45/7								33
795 AAC 26/7								34
1557.4 ACSR/TW								35
	234,140,526	3,437,321,298	3,671,461,824	523,824	17,542,520	2,406,374	20,472,718	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 2016/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	PAINTER, UT	RAILROAD, UT	138.00	138.00	Wood - H	7.00		1
2	PAROWAN, UT	WEST CEDAR, UT	138.00	138.00	Wood - H	21.00		1
3	PARRISH, UT	TERMINAL #1, UT	138.00	138.00	Steel - SP	16.00		1
4	PARRISH, UT	TERMINAL #2, UT	138.00	138.00			14.00	1
5	PARRISH #105, UT	TERMINAL, UT	138.00	138.00	Steel - SP	14.00		1
6	PARRISH, UT	TAP TO N SALT LAKE, UT	138.00	138.00	Steel - SP		8.00	1
7	RAILROAD, UT	CANYON COMP, WY	138.00	138.00	Wood - H	17.00		1
8	CENTRAL (UAMPS) #2, UT	SAINT GEORGE, UT	138.00	138.00	Steel - SP	20.00		1
9	CENTRAL (UAMPS) #3, UT	SAINT GEORGE, UT	138.00	138.00	Steel - SP		20.00	1
10	RED BUTTE, UT	ST GEORGE, UT	138.00	138.00	Steel - SP	1.00		1
11	RED BUTTE, UT	WEST CEDAR, UT	138.00	138.00	Wood - H	49.00		1
12	RIVERDALE, UT	EAST LAYTON, UT	138.00	138.00	Steel - SP		7.00	1
13	SHICK, UT	PARRISH, UT	138.00	138.00	Wood - H		10.00	1
14	SILVER CREEK, UT	JORDANELLE, UT	138.00	138.00	Wood - SP	10.00		1
15	SPANISH FORK, UT	TANNER, UT	138.00	138.00	Wood - H	10.00		1
16	SUNRISE, UT	OQUIRRH, UT	138.00	138.00	Wood - SP		2.00	1
17	SYRACUSE, UT	CLEARFIELD SOUTH, UT	138.00	138.00	Steel - SP	1.00		1
18	SYRACUSE, UT	PARRISH, UT	138.00	138.00	Steel Tower	15.00		1
19	SYRACUSE, UT	ANGEL #1, UT	138.00	138.00			9.00	1
20	TAP TO ANGEL NORTH, UT	TAP TO PARRISH, UT	138.00	138.00	Wood - H	13.00		1
21	TAYLORSVILLE , UT	90TH SOUTH, UT	138.00	138.00	Wood - SP	6.00	2.00	1
22	TERMINAL, UT	KENNECOTT, UT	138.00	138.00	Steel - SP	9.00		1
23	TERMINAL, UT	ROWLEY, UT	138.00	138.00	Wood - H	53.00		1
24	TERMINAL, UT	MIDVALLEY #1, UT	138.00	138.00	Wood - H	7.00		1
25	TERMINAL, UT	MIDVALLEY #2, UT	138.00	138.00	Wood - H	7.00		1
26	TERMINAL, UT	TOOELE, UT	138.00	138.00	Wood - H	24.00	6.00	1
27	TERMINAL, UT	WEST VALLEY, UT	138.00	138.00	Wood - SP	7.00		1
28	THREEMILE KNOLL, ID	GRACE #1, ID	138.00	138.00	Wood - H	17.00		1
29	THREEMILE KNOLL, ID	GRACE #2, ID	138.00	138.00	Wood - H	17.00		1
30	THREEMILE KNOLL, ID	MONSANTO #1, ID	138.00	138.00	Wood - H	2.00		1
31	THREEMILE KNOLL, ID	MONSANTO #2, ID	138.00	138.00	Steel - SP	2.00		1
32	TIMP #1, UT	DYNAMO, UT	138.00	138.00	Steel - SP	2.00		1
33	TIMP #2, UT	DYNAMO, UT	138.00	138.00			2.00	1
34	TIMP, UT	HALE, UT	138.00	138.00	Steel - SP	4.00		1
35	TIMP, UT	SPANISH FORK, UT	138.00	138.00	Wood - H	23.00		1
36					TOTAL	16,964.00	654.00	284

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 2016/Q4

TRANSMISSION LINE STATISTICS (Continued)

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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.
1272 ACSR 45/7								1
397.5 ACSR 26/7								2
795 AAC 45/7								3
795 AAC 26/7								4
795 AAC 45/7								5
795 AAC 26/7								6
795 ACSR 26/7								7
1272 ACSR 45/7								8
1272 ACSR 45/7								9
1272 ACSR 45/7								10
397.5 ACSR 26/7								11
795 AAC 26/7								12
250 CUHD /12								13
795 AAC 26/7								14
1272 ACSR 45/7								15
								16
1272 ACSR 45/7								17
1272 ACSR 45/7								18
250 CUHD /12								19
795 AAC /37								20
795 AAC /37								21
795 AAC 26/7								22
795 AAC /37								23
1272 ACSR 45/7								24
1272 AAC /61								25
397.5 ACSR 26/7								26
								27
250 CUHD /12								28
1272 ACSR 45/7								29
1272 AAC /61								30
1272 ACSR 45/7								31
								32
								33
								34
								35
	234,140,526	3,437,321,298	3,671,461,824	523,824	17,542,520	2,406,374	20,472,718	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 2016/Q4

TRANSMISSION LINE STATISTICS

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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	TIMP, UT	VINEYARD, UT	138.00	138.00	Wood - SP	2.00		
2	TREASURETON, ID	GRACE, ID	138.00	138.00	Steel Tower	25.00		1
3	TREASURETON, ID	GRACE #2, ID	138.00	138.00			25.00	1
4	TREASURETON, ID	ONEIDA, ID	138.00	138.00	Wood - H	6.00		1
5	TRI-CITY, UT	SUNRISE, ID	138.00	138.00	Wood - SP	22.00		1
6	TRI-CITY, UT	BANGERTER, UT	138.00	138.00	Wood - SP	6.00	12.00	1
7	TRI-CITY, UT	WESTFIELD, UT	138.00	138.00	Wood - H	15.00		1
8	WEST CEDAR, UT	THREE PEAKS, UT	138.00	138.00	Wood - SP	20.00		1
9	WEST VALLEY, UT	OQUIRRH, UT	138.00	138.00	Wood - H	9.00		1
10	WESTFIELD, UT	HALE, UT	138.00	138.00	Wood - H	14.00		1
11	WHEELON, UT	AMERICAN FALLS, ID	138.00	138.00	Wood - H	86.00		1
12	WHEELON #1, UT	TREASURETON, ID	138.00	138.00	Steel Tower	29.00		1
13	WHEELON #2, UT	TREASURETON, ID	138.00	138.00			29.00	1
14	WHEELON #3, UT	TREASURETON, ID	138.00	138.00	Wood - H	29.00		1
15	FORT DOUGLAS, UT	MCCLELLAND, UT	138.00	138.00	Wood - SP	3.00		1
16	CAMERON, UT	MILFORD, UT	138.00	138.00	Wood - SP	25.00		1
17	EAGLE MOUNTAIN, UT	PONY EXPRESS, UT	138.00	138.00	Wood - SP	10.00		1
18	CLOVER, UT	BURRASTON PONDS	138.00	138.00	Wood - SP	2.00		1
19	CROYDON, UT	RAILROAD, WY	138.00	138.00	Wood - SP	38.00		1
20	GRAPHITE, UT	MOUNTAIN VIEW, UT	138.00	138.00	Wood - SP	1.00		1
21	HIGHLAND, UT	BULL RIVER (LEHI #5), UT	138.00	138.00	Wood - SP	5.00		1
22	138kV costs and expenses							
23								
24	Subtotal 138kV					2,163.00	207.00	147
25								
26	All 115kV Lines					1,666.00		
27								
28	All 69kV Lines					2,923.00		
29								
30	All 57kV Lines					111.00		
31								
32	All 46kV Lines					2,541.00		
33								
34								
35								
36					TOTAL	16,964.00	654.00	284

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 2016/Q4

TRANSMISSION LINE STATISTICS (Continued)

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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.
1272 ACSR 45/7								1
250 CUHD /12								2
250 CUHD /12								3
250 CUHD /12								4
								5
								6
1272 ACSR 45/7								7
795 AAC 26/7								8
								9
795 AAC 26/7								10
250 CUHD /12								11
250 CUHD /12								12
250 CUHD /12								13
250 CUHD /12								14
								15
397.5 ACSR 26/7								16
795 ACSR 26/7								17
397.5 ACSR 26/7								18
1272 ACSR 45/7								19
397.5 ACSR 26/7								20
1272 ACSR 45/7								21
	24,075,933	379,880,040	403,955,973	163,186	1,568,566	187,509	1,919,261	22
								23
	24,075,933	379,880,040	403,955,973	163,186	1,568,566	187,509	1,919,261	24
								25
	5,201,683	193,141,097	198,342,780	62,881	3,584,058	467,033	4,113,972	26
								27
	8,296,714	281,925,085	290,221,799	23,430	3,203,969	221,169	3,448,568	28
								29
	52,655	12,078,789	12,131,444	2,336	59,219	1,320	62,875	30
								31
	10,591,146	265,382,941	275,974,087	28,775	2,321,343	81,759	2,431,877	32
								33
								34
								35
	234,140,526	3,437,321,298	3,671,461,824	523,824	17,542,520	2,406,374	20,472,718	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. For further discussion, see also page 328, Transmission of electricity for others, in this Form No. 1.

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	78.0%	22.0%
Midpoint – Hemingway	63.0%	37.0%

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 Company. 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 Company. 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 Company. 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 Company. 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 Company. 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 81.7%, Idaho Power Company 18.3%. 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	70.8%	29.2%
Populus – Borah #1	70.8%	29.2%

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	70.8%	29.2%
Populus – Kinport	70.8%	29.2%

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 70.8%, Idaho Power Company 29.2%. 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 35.6%, Idaho Power Company 64.4%. 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 35.6%, Idaho Power Company 64.4%. 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 26.8%, Idaho Power Company 73.2%. Plant cost and operation and maintenance costs reported for this line reflect PacifiCorp’s share.

Schedule Page: 422.2 Line No.: 3 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.: 3 Column: i

1557 ACSS/TW 45/7

Schedule Page: 422.2 Line No.: 18 Column: a

Complete name is Gonder (NV Energy), UT - NV State.

Schedule Page: 422.2 Line No.: 21 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 59.2%, Idaho Power Company 40.8%.

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 Big Grassy - Jefferson 161kV line is jointly owned by PacifiCorp and Idaho Power company. Ownership of the line is as follows: PacifiCorp 62.2%, Idaho Power Company 37.8%. Plant costs and operation and maintenance costs reported for this line reflect PacifiCorp's share.

Schedule Page: 422.3 Line No.: 35 Column: a

The Antelope - Goshen 161kV line is jointly owned by PacifiCorp and Idaho Power Company. Ownership of the line is as follows: PacifiCorp 78.1%, Idaho Power Company 21.9%. Plant cost and operation and maintenance costs reported for this line reflect PacifiCorp's share.

Schedule Page: 422.4 Line No.: 9 Column: a

The Goshen - Jefferson 161kV line is jointly owned by PacifiCorp and Idaho Power Company. Ownership of the line is as follows: PacifiCorp 62.2%, Idaho Power Company 37.8%. Plant cost and operation and maintenance costs reported for this line reflect PacifiCorp's share.

Schedule Page: 422.4 Line No.: 22 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 33.3%, Idaho Power Company 66.7%. Plant cost and operation and maintenance costs reported for this line reflect PacifiCorp's share.

Schedule Page: 422.4 Line No.: 23 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 33.3%, Idaho Power Company 66.7%. Plant cost and operation and maintenance costs reported for this line reflect PacifiCorp's share.

Schedule Page: 422.4 Line No.: 27 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 15 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 20 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 21 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 35 Column: b

Complete name is Bingham Canyon (KCC), UT.

Schedule Page: 422.7 Line No.: 8 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.: 9 Column: a

See footnote on page 422.7, line 8, column (a).

Schedule Page: 422.7 Line No.: 16 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 27 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: 422.7 Line No.: 34 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 35 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 5 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.: 9 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 11 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 96.4%, Idaho Power Company 3.6%. Plant cost and operation and maintenance costs reported for this line reflect PacifiCorp’s share.

Schedule Page: 422.8 Line No.: 15 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 18 Column: b

Complete name is Burraston Ponds Metering, UT.

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 2016/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	ARROWHEAD, WY	FIREHOLE, WY	9.00	Wood - H	8.00	1	1
2	TIMP, UT	VINEYARD, UT	2.00	Wood - SP	25.00	1	1
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
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28							
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31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		11.00		33.00	2	2

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/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.
795	ACSR		230		674,850	328,943		1,003,793	1
1272	ACSR	Vertical 5'	138		1,539,259	1,681,622	-142,591	3,078,290	2
									3
									4
									5
									6
									7
									8
									9
									10
									11
									12
									13
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									20
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									38
									39
									40
									41
									42
									43
					2,214,109	2,010,565	-142,591	4,082,083	44

Schedule Page: 424 Line No.: 1 Column: j

Horizontal 9 feet, 7 inches

Schedule Page: 424 Line No.: 2 Column: m

Line costs include structure and line replacement charges to alter the previous single circuit 46kV transmission line.

Schedule Page: 424 Line No.: 2 Column: n

Refer to footnote on line 2, column (m).

Schedule Page: 424 Line No.: 2 Column:

Refer to footnote on line 2, column (m).

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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
25	1					2
6	1					3
1	3					4
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

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	TOTAL		690.00	391.00	12.47
18	Number of Substations-5				
19					
20	IDAHO				
21	ALEXANDER	DISTRIBUTION-UNATTEN	46.00	12.47	
22	AMMON	DISTRIBUTION-UNATTEN	69.00	12.47	
23	ANDERSON	DISTRIBUTION-UNATTEN	69.00	12.47	
24	ARCO	DISTRIBUTION-UNATTEN	69.00	12.47	
25	ARIMO	DISTRIBUTION-UNATTEN	46.00	12.47	
26	BANCROFT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
27	BELSON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
28	BERENICE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
29	CAMAS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	CANYON CREEK SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
31	CHESTERFIELD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	CLEMENTS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	CLIFTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	COVE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	DOWNEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	DUBOIS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	EASTMONT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	EGIN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	EIGHT MILE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	GEORGETOWN 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.
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
725	14					17
						18
						19
						20
4	1					21
14	1					22
20	1					23
6	1					24
7	1					25
4	1					26
12	1					27
10	1					28
14	1					29
20	1					30
5	1					31
5	1					32
4	1					33
6	1					34
5	1					35
12	1					36
14	1					37
14	1					38
4	1					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 2016/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	GRACE CITY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	HAMER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	HAYES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	HENRY SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
5	HOLBROOK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	HOOPES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	HORSLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
8	IDAHO FALLS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	INDIAN CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	JEFFCO SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
11	KETTLE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
12	LAVA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	LUND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	MCCAMMON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	MENAN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	MERRILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
17	MILLER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	MONTPELIER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	MOODY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	NEWDALE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	OSGOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	PRESTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	RAYMOND SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	RENO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	REXBURG SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	RIRIE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	ROBERTS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
28	RUBY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
29	SAND CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	SANDUNE SUB	DISTRIBUTION-UNATTEN	67.00	24.90	
31	SHELLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	SMITH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	SOUTH FORK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	SPUD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	ST. CHARLES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	SUGAR CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	SUNNYDELL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	TANNER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	TARGHEE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	THORNTON 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 2016/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
5	1					1
14	1					2
9	1					3
1	1					4
6	1					5
9	1					6
4	1					7
20	1					8
3	1					9
22	1					10
14	1					11
6	1					12
5	1					13
3	1					14
10	1					15
20	1					16
5	1					17
8	1					18
14	1					19
20	1					20
20	1					21
12	1					22
2	1					23
20	1					24
32	2					25
9	1					26
8	1					27
7	1					28
40	2					29
30	1					30
20	1					31
20	1					32
14	1					33
8	1					34
5	1					35
12	1					36
13	1					37
4	1					38
4	1					39
7	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	UCON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
2	WATKINS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	WEBSTER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	WESTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	WINDSPER SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
6	TOTAL		4000.00	867.43	
7	Number of Substations-65				
8					
9	CINDER BUTTE SUB	T/D-UNATTENDED	161.00	12.47	
10	MALAD SUB	T/D-UNATTENDED	138.00	46.00	12.47
11	MUD LAKE SUB	T/D-UNATTENDED	69.00	12.47	
12	RIGBY SUB	T/D-UNATTENDED	161.00	12.47	69.00
13	SAINT ANTHONY SUB	T/D-UNATTENDED	69.00	46.00	12.47
14	TOTAL		598.00	129.41	93.94
15	Number of Substations-5				
16					
17	AMPS SUB	TRANSMISSION-UNATTEN	230.00	69.00	12.47
18	ANTELOPE SUB	TRANSMISSION-UNATTEN	230.00	161.00	13.80
19	ASHTON PLANT	TRANSMISSION-UNATTEN	46.00	12.47	2.40
20	BIG GRASSY SUB	TRANSMISSION-UNATTEN	161.00	69.00	
21	BONNEVILLE SUB	TRANSMISSION-UNATTEN	161.00	69.00	
22	CONDA SUB	TRANSMISSION-UNATTEN	138.00	46.00	
23	FISH CREEK SUB	TRANSMISSION-UNATTEN	161.00	46.00	
24	FRANKLIN SUB	TRANSMISSION-UNATTEN	138.00	46.00	
25	GOSHEN SUB	TRANSMISSION-UNATTEN	345.00	161.00	69.00
26	GRACE SUB	TRANSMISSION-UNATTEN	161.00	138.00	12.50
27	JEFFERSON SUB	TRANSMISSION-UNATTEN	161.00	69.00	
28	MIDPOINT SUB	TRANSMISSION-UNATTEN	500.00	345.00	
29	OVID SUB	TRANSMISSION-UNATTEN	138.00	69.00	
30	SCOVILLE SUB	TRANSMISSION-UNATTEN	138.00	69.00	
31	SUGARMILL SUB	TRANSMISSION-UNATTEN	161.00	46.00	69.00
32	THREEMILE KNOLL SUB	TRANSMISSION-UNATTEN	345.00	138.00	46.00
33	TREASURETON SUB	TRANSMISSION-UNATTEN	230.00	138.00	
34	TOTAL		3444.00	1691.47	225.17
35	Number of Substations-17				
36					
37	MONTANA				
38	BROADVIEW SUB	TRANSMISSION-UNATTEN	500.00	230.00	
39	COLSTRIP SUB	TRANSMISSION-UNATTEN	500.00	230.00	
40	YELLOWTAIL SUB	TRANSMISSION-UNATTEN	230.00	161.00	

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
14	1					2
20	1					3
4	1					4
20	1					5
736	67					6
						7
						8
30	1					9
71	4	1				10
14	1					11
189	4					12
40	2					13
344	12	1				14
						15
						16
75	1					17
250	1					18
15	1					19
67	1					20
67	1					21
67	1					22
25	3					23
75	1					24
908	4					25
217	2					26
233	3					27
1500	1	1				28
30	1					29
76	2					30
168	3					31
775	2					32
533	2					33
5081	30	1				34
						35
						36
						37
32	2					38
68	2					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 2016/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		1230.00	621.00	
2	Number of Substations-3				
3					
4	OREGON				
5	26TH STREET	DISTRIBUTION-UNATTEN	20.80	4.16	
6	35TH STREET	DISTRIBUTION-UNATTEN	20.80	2.40	
7	AGNESS AVE	DISTRIBUTION-UNATTEN	115.00	12.47	
8	ALDERWOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	ARLINGTON	DISTRIBUTION-UNATTEN	69.00	12.47	
10	ATHENA	DISTRIBUTION-UNATTEN	69.00	12.47	
11	BANDON TIE SUB	DISTRIBUTION-UNATTEN	20.80	12.47	
12	BEACON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	BEALL LANE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
14	BEATTY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
15	BELKNAP SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
16	BLALOCK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
17	BLOSS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
18	BLY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	BOISE CASCADE SUB	DISTRIBUTION-UNATTEN	69.00	11.00	
20	BONANZA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	BOND STREET SUB	DISTRIBUTION-UNATTEN	69.00	12.50	
22	BROOKHURST SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
23	BROWNSVILLE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
24	BRYANT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	BUCHANAN SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
26	BUCKAROO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	CAMPBELL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
28	CANNON BEACH SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
29	CANYONVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
30	CARNES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	CASEBEER SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
32	CAVEMAN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
33	CHERRY LANE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	CHILOQUIN MARKET SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	CHINA HAT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	CIRCLE BLVD SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
37	CLEVELAND AVE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	CLOAKE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
39	COBURG SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
40	COLISEUM SUB	DISTRIBUTION-UNATTEN	20.80	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 2016/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.
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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)	
200	5					1
						2
						3
						4
5	1					5
30	6					6
25	1					7
45	2					8
5	1					9
9	1					10
8	3	1				11
11	3					12
25	1					13
6	1					14
40	2					15
2	3					16
32	2					17
8	3					18
3	1					19
8	3					20
25	1					21
50	2					22
13	1					23
34	2					24
45	2					25
34	2					26
20	2					27
13	1					28
25	1					29
9	3					30
20	1					31
45	2					32
25	1					33
9	3					34
25	1					35
80	2					36
45	2					37
20	1					38
10	3					39
9	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 2016/Q4

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	COLUMBIA SUB	DISTRIBUTION-UNATTEN	115.00	12.47	57.00
2	COOS RIVER SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
3	COQUILLE SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
4	CREEK SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
5	CROOKED RIVER RANCH SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
6	CROWFOOT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
7	CULLY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
8	CULVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	DAIRY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	DALLAS SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
11	DALREED SUB	DISTRIBUTION-UNATTEN	230.00	34.40	
12	DESCHUTES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	DEVILS LAKE SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
14	DIXON SUB	DISTRIBUTION-UNATTEN	115.00	4.16	
15	DODGE BRIDGE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
16	DOWELL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
17	EASY VALLEY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
18	EMPIRE SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
19	ENTERPRISE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	FERN HILL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
21	FIELDER CREEK SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
22	FOOTHILLS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	FRALEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	GARDEN VALLEY SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
25	GAZLEY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
26	GLENDALE SUB	DISTRIBUTION-UNATTEN	230.00	12.47	
27	GLENEDEN SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
28	GLIDE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
29	GOLD HILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	GORDON HOLLOW SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	GOSHEN SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
32	GRANT STREET SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
33	GRASS VALLEY SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
34	GREEN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	GRIFFIN CREEK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
36	HAMAKER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	HARRISBURG SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
38	HENLEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	HERMISTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	HILLVIEW SUB	DISTRIBUTION-UNATTEN	115.00	20.80	

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 2016/Q4

SUBSTATIONS (Continued)

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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)	
55	2	1				1
20	1					2
40	2					3
5	1					4
25	2					5
20	1					6
25	1					7
13	1					8
25	1					9
50	2					10
95	4					11
25	1					12
50	2					13
7	1					14
13	1					15
20	1					16
45	2					17
20	1					18
19	2					19
12	1					20
25	1					21
21	4					22
5	3					23
20	1					24
8	4					25
25	2					26
6	1					27
12	1					28
11	3					29
6	1					30
20	1					31
45	2					32
1	4					33
25	1					34
20	1					35
8	3					36
13	1					37
6	3					38
40	1					39
45	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	HINKLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
2	HOLLADAY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
3	HOLLYWOOD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
4	HOOD RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
5	HORNET SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	HUMBUG CREEK SUB	DISTRIBUTION-UNATTEN	67.00	12.50	
7	HUNTERS CIRCLE TEMP SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	ILLAHEE FLATS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
9	INDEPENDENCE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
10	JACKSONVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	69.00
11	JEFFERSON SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
12	JEROME PRAIRIE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
13	JORDAN POINT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
14	JOSEPH SUB	DISTRIBUTION-UNATTEN	20.80	12.47	
15	JUNCTION CITY SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
16	KENWOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
17	KILLINGWORTH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	KNAPPA SVENSEN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
19	LAKEPORT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	LANCASTER SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
21	LEBANON SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
22	LINCOLN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
23	LOCKHART SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
24	LYONS SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
25	MADRAS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	MALLORY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
27	MARYS RIVER SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
28	MEDCO SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
29	MEDFORD	DISTRIBUTION-UNATTEN	115.00	12.47	
30	MERLIN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
31	MERRILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	MINAM SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	MODOC SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	MORO SUB	DISTRIBUTION-UNATTEN	20.80	2.40	
35	MURDER CREEK SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
36	MYRTLE CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	MYRTLE POINT SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
38	NELSCOTT SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
39	NEW O'BRIEN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
40	OAK KNOLL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/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)	
20	1					1
75	3					2
50	2					3
40	2					4
20	1					5
9	1					6
12	1					7
2	1					8
20	1					9
75	2					10
12	1					11
20	1					12
20	1					13
6	1	1				14
22	2					15
3	3					16
40	2					17
6	1					18
50	2					19
12	3					20
40	2					21
105	3					22
40	2					23
25	2					24
25	2					25
25	1					26
20	1					27
20	1					28
67	8					29
45	2					30
17	6					31
	1					32
6	3					33
2	3					34
100	4					35
14	1					36
9	1					37
4	1					38
9	1					39
45	2					40

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/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	OAKLAND SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
2	OREMET SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
3	OVERPASS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	PALLETTE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
5	PARK STREET SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
6	PARKROSE SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
7	PENDLETON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	PILOT ROCK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	POWELL BUTTE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
10	PRINEVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
11	PROVOLT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
12	QUEEN AVE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
13	RED BLANKET SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
14	REDMOND SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
15	RIDDLE VENEER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
16	ROGUE RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
17	ROSEBURG SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
18	ROSS AVE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	ROXY ANN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
20	RUCH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	RUNNING Y SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
22	RUSSELLVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
23	SCENIC SUB	DISTRIBUTION-UNATTEN	115.00	12.47	69.00
24	SCIO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	SEASIDE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
26	SELMA SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
27	SHASTA WAY SUB	DISTRIBUTION-UNATTEN	12.47	4.16	
28	SHEVLIN PARK SUB	DISTRIBUTION-UNATTEN	69.00	12.50	
29	SIMTAG BOOSTER PUMP	DISTRIBUTION-UNATTEN	34.50	4.16	
30	SOUTH DUNES SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
31	SOUTHGATE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
32	SPRAGUE RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	STATE STREET SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
34	STAYTON SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
35	STEAMBOAT SUB	DISTRIBUTION-UNATTEN	115.00	7.20	
36	STEVENS ROAD SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
37	SUTHERLIN SUB	DISTRIBUTION-UNATTEN	115.00	12.00	
38	SWEET HOME SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
39	TAKELMA SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
40	TALENT 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.
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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.
8	1					1
75	2					2
45	2					3
1	1	1				4
40	2					5
39	2					6
46	7	1				7
22	2					8
12	1					9
50	2					10
11	3					11
50	2					12
2	3					13
50	2					14
25	1					15
25	2					16
50	2					17
9	3					18
25	1					19
9	1					20
9	1					21
45	2					22
70	3					23
8	1					24
40	2					25
9	1					26
2	3					27
25	1					28
19	2					29
9	1					30
20	1					31
7	3					32
40	2					33
55	2					34
	1					35
50	2					36
25	1					37
42	2					38
12	1					39
50	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/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	TEXUM SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
2	TILLER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
3	TOLO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	TURKEY HILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
5	UMAPINE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	UMATILLA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	VERNON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	VILAS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
9	VILLAGE GREEN SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
10	VINE STREET SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
11	WALLOWA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
12	WARM SPRINGS SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
13	WARRENTON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
14	WASCO SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
15	WECOMA BEACH SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
16	WESTERN KRAFT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
17	WESTON SUB	DISTRIBUTION-UNATTEN	70.60	13.09	
18	WESTSIDE HYDRO/SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	WEYERHAUSER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	WHITE CITY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
21	WILLOW COVE SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
22	WINSTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	YEW AVENUE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
24	YOUNGS BAY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
25	TOTAL		15661.87	2512.06	195.00
26	Number of Substations-180				
27					
28	ALBINA SUB	T/D-UNATTENDED	115.00	12.47	69.00
29	APPLEGATE SUB	T/D-UNATTENDED	115.00	69.00	12.47
30	ASHLAND SUB	T/D-UNATTENDED	115.00	12.47	7.20
31	BEND PLANT SUB	T/D-UNATTENDED	69.00	13.09	12.47
32	CAVE JUNCTION SUB	T/D-UNATTENDED	115.00	12.47	69.00
33	HAZELWOOD SUB	T/D-UNATTENDED	115.00	69.00	12.47
34	KNOTT SUB	T/D-UNATTENDED	115.00	12.47	57.00
35	MILE HI SUB	T/D-UNATTENDED	115.00	69.00	12.47
36	PILOT BUTTE SUB	T/D-UNATTENDED	230.00	69.00	12.47
37	RIDDLE SUB	T/D-UNATTENDED	115.00	69.00	
38	SAGE ROAD SUB	T/D-UNATTENDED	115.00	12.47	
39	WINCHESTER SUB	T/D-UNATTENDED	115.00	12.47	69.00
40	TOTAL		1449.00	432.91	333.55

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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.
25	1					1
1	1					2
11	1					3
13	3					4
20	1					5
25	2					6
50	2					7
25	1					8
40	2					9
20	1					10
7	1					11
12	3					12
25	2					13
2	3					14
3	1					15
50	2					16
25	1					17
22	9					18
40	2					19
60	3					20
28	3					21
22	3					22
25	1					23
37	2					24
4615	345	5				25
						26
						27
177	9					28
65	2					29
20	1					30
31	3					31
70	2					32
106	3					33
162	5					34
39	4					35
400	4					36
75	2					37
40	2					38
75	5					39
1260	42					40

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Number of Substations-12				
2					
3	LEMOLO #1 HYDRO	TRANSMISSION-ATTENDE	11.50	12.50	
4	CALAPOOYA SUB	TRANSMISSION-UNATTEN	230.00	69.00	
5	CHILOQUIN SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
6	COLD SPRINGS SUB	TRANSMISSION-UNATTEN	230.00	69.00	2.40
7	COVE SUB	TRANSMISSION-UNATTEN	230.00	69.00	
8	DIAMOND HILL SUB	TRANSMISSION-UNATTEN	230.00	69.00	
9	DIXONVILLE 115/230 SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
10	DIXONVILLE 500 SUB	TRANSMISSION-UNATTEN	500.00	230.00	
11	FISH HOLE SUB	TRANSMISSION-UNATTEN	115.00	69.00	
12	FRY SUB	TRANSMISSION-UNATTEN	230.00	115.00	
13	GRANTS PASS SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
14	HURRICANE SUB	TRANSMISSION-UNATTEN	230.00	69.00	2.40
15	ISTHMUS SUB	TRANSMISSION-UNATTEN	230.00	115.00	
16	KENNEDY SUB	TRANSMISSION-UNATTEN	69.00	57.00	
17	KLAMATH FALLS SUB	TRANSMISSION-UNATTEN	230.00	69.00	
18	LONE PINE SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
19	MALIN SUB	TRANSMISSION-UNATTEN	500.00	230.00	69.00
20	MERIDIAN SUB	TRANSMISSION-UNATTEN	500.00	230.00	
21	MONPAC SUB	TRANSMISSION-UNATTEN	115.00	69.00	
22	NICKEL MOUNTAIN SUB	TRANSMISSION-UNATTEN	230.00	115.00	
23	PARRISH GAP SUB	TRANSMISSION-UNATTEN	230.00	69.00	12.47
24	PONDEROSA SUB	TRANSMISSION-UNATTEN	230.00	115.00	
25	PROSPECT CENTRAL SUB	TRANSMISSION-UNATTEN	115.00	69.00	
26	ROBERTS CREEK SUB	TRANSMISSION-UNATTEN	115.00	69.00	
27	TROUTDALE SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
28	TUCKER SUB	TRANSMISSION-UNATTEN	115.00	69.00	
29	WHETSTONE SUB	TRANSMISSION-UNATTEN	230.00	115.00	12.47
30	TOTAL		6065.50	2737.50	443.74
31	Number of Substations-27				
32					
33	UTAH				
34	106TH SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
35	118TH SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
36	23RD ST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	70TH SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
38	ALTAVIEW SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	AMALGA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	AMERICAN FORK SUB	DISTRIBUTION-UNATTEN	138.00	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 2016/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
						1
						2
2	3					3
75	1					4
119	4					5
66	2					6
67	3					7
75	1					8
343	6					9
650	3	1				10
7	3					11
500	2					12
473	5					13
29	2					14
250	1					15
33	1					16
251	6	1				17
733	10					18
775	4	1				19
1300	6	1				20
50	1					21
114	1					22
150	1					23
500	2					24
30	3					25
50	1					26
500	3					27
100	2					28
250	1					29
7492	78	4				30
						31
						32
						33
30	1					34
30	1					35
12	1					36
30	1					37
45	2					38
11	1					39
30	1					40

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ARAGONITE	DISTRIBUTION-UNATTEN	46.00	7.20	
2	AURORA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	BANGERTER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
4	BEAR RIVER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	BENJAMIN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	BINGHAM SUB	DISTRIBUTION-UNATTEN	46.00	7.62	
7	BLUE CREEK	DISTRIBUTION-UNATTEN	46.00	12.47	
8	BLUFF SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	BLUFFDALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	BOTHWELL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	BRIAN HEAD SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
12	BRIGHTON SUB	DISTRIBUTION-UNATTEN	46.00	24.90	
13	BROOKLAWN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	BRUNSWICK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	BURTON SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
16	BUSH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	CANNON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	CANYONLANDS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	CAPITOL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	CARBIDE SUB	DISTRIBUTION-UNATTEN	69.00	7.20	
21	CARBONVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	CARLISLE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
23	CASTO SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	CENTERVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	CENTRAL SUB	DISTRIBUTION-UNATTEN	43.80	12.47	
26	CHAPEL HILL SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
27	CHERRYWOOD SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
28	CIRCLEVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
29	CLEAR CREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	CLEAR LAKE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	CLEARFIELD SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
32	CLINTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
33	CLIVE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	COALVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	COLD WATER CANYON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
36	COLEMAN SUB	DISTRIBUTION-UNATTEN	138.00	69.00	12.47
37	COLTON WELL SUB	DISTRIBUTION-UNATTEN	46.00	2.40	
38	COMMERCE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
39	COPPER HILLS SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
40	CORINNE 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 2016/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
1	1					1
3	1					2
50	2					3
17	2					4
2	1					5
25	1					6
2	3					7
1	3					8
9	1					9
4	1					10
14	1					11
29	2					12
6	1					13
60	3					14
11	3					15
9	1					16
12	1					17
1	1					18
20	1					19
3	1					20
6	1					21
30	1					22
25	1					23
22	1					24
9	1					25
30	1					26
50	2					27
3	1					28
4	1					29
	3					30
60	2					31
50	2					32
4	1					33
6	1					34
30	1					35
106	4					36
1	3					37
30	1					38
30	1					39
3	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/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	COVE FORT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	COZYDALE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
3	CROSS HOLLOW SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
4	CUDAHY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
5	DAMMERON VALLEY SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
6	DECKER LAKE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
7	DELLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
8	DELTA SUB	DISTRIBUTION-UNATTEN	46.00	69.00	
9	DEWEYVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	DIMPLE DELL SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
11	DRAPER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	EAST BENCH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
13	EAST HYRUM SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	EAST LAYTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
15	EAST MILLCREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	EDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	ELBERTA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	ELK MEADOWS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	ELSINORE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	EMERY CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	EMIGRATION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	ENOCH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
23	ENTERPRISE VALLEY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
24	EUREKA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	FARMINGTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
26	FAYETTE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
27	FERRON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
28	FIELDING SUB	DISTRIBUTION-UNATTEN	46.00	12.00	
29	FIFTH WEST SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
30	FLUX SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	FOOL CREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	FORT DOUGLAS	DISTRIBUTION-UNATTEN	138.00	13.20	
33	FOUNTAIN GREEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	FREEDOM SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
35	FRUIT HEIGHTS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	GARDEN CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	GATEWAY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	GOLD RUSH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
39	GORDON AVENUE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
40	GOSHEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/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
30	1					2
22	1					3
30	1					4
42	1					5
55	2					6
6	1					7
48	3					8
4	1					9
60	2					10
23	2					11
30	1					12
6	1					13
60	2					14
20	1					15
19	2					16
5	1					17
3	1					18
2	1					19
3	3					20
25	1					21
14	1					22
10	1					23
3	1					24
30	1					25
1	2					26
5	1					27
6	1					28
50	2					29
4	1					30
2	1					31
40	1					32
7	1					33
	1					34
22	1					35
12	1					36
14	1	2				37
30	1					38
30	1					39
2	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	GRANGER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	GRANTSVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	GUNNISON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	HAMMER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
5	HAVASU SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	HELPER CITY SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
7	HERRIMAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
8	HIGHLAND DIST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	HOGGARD SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
10	HOLDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	HOLLADAY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	HUNTER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	HUNTINGTON CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	IRON MOUNTAIN SUB	DISTRIBUTION-UNATTEN	34.50	7.20	
15	IRONTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	IVINS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
17	JORDAN NARROWS SUB	DISTRIBUTION-UNATTEN	46.00	2.40	
18	JORDAN PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
19	JORDANELLE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
20	JUAB SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	JUNCTION SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	KAIBAB SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	KAMAS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	KEARNS SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
25	KENSINGTON SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
26	KYUNE SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
27	LAKE PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
28	LAYTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	LEGRANDE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	LEWISTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	LINCOLN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	LINDON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	LISBON SUB	DISTRIBUTION-UNATTEN	70.60	12.47	
34	LOAFER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	LOGAN CANYON SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
36	LONE TREE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
37	LOWER BEAVER SUB	DISTRIBUTION-UNATTEN	46.00	6.60	
38	LYNNDYL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	MAESER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	MAGNA SUB	DISTRIBUTION-UNATTEN	138.00	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 2016/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
23	1					2
11	2					3
60	2					4
3	1					5
3	3					6
30	1					7
25	1					8
50	2					9
4	1					10
32	2					11
22	1					12
12	2					13
1	1					14
2	1					15
22	1					16
13	2					17
30	1					18
30	1					19
4	1					20
3	1					21
5	1					22
7	1					23
60	2					24
7	1					25
	1					26
53	2					27
40	2					28
2	1					29
14	1					30
20	1					31
20	1					32
3	1					33
	1					34
1	1					35
20	1					36
1	1					37
4	1					38
12	1					39
30	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 2016/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	MANILA SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
2	MANTUA SUB	DISTRIBUTION-UNATTEN	44.00	12.47	
3	MAPLETON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	MARRIOTT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	MARYSVALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	MATHIS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	MCCORNICK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
8	MCKAY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	MEADOWBROOK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	46.00
10	MEDICAL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	MIDLAND SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
12	MIDVALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	MILFORD SUB	DISTRIBUTION-UNATTEN	138.00	46.00	
14	MILFORD TV SUB	DISTRIBUTION-UNATTEN	46.00	13.20	
15	MINERSVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	MOAB CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
17	MOORE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	MORGAN SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
19	MORONI SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	MOUNTAIN DELL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	MOUNTAIN GREEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	MYTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	NEW HARMONY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	NEWGATE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	NEWTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	NIBLEY SUB	DISTRIBUTION-UNATTEN	138.00	24.90	
27	NORTH BENCH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	NORTH FIELDS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	NORTH LOGAN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	NORTH OGDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	NORTH SALT LAKE SUB	DISTRIBUTION-UNATTEN	46.00	13.20	
32	NORTHEAST SUB	DISTRIBUTION-UNATTEN	46.00	12.50	
33	NORTHRIDGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	OAKLAND AVE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	OAKLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	OLYMPUS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	OPHIR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	ORANGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	ORANGEVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	OREM 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) (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.
22	1					1
2	1					2
14	1					3
20	1					4
3	1					5
9	1					6
6	1					7
20	1					8
42	2					9
57	4					10
30	1					11
25	1					12
89	2					13
	1					14
2	1					15
19	2					16
3	1					17
7	2					18
6	1					19
5	1					20
6	1					21
6	1					22
7	1					23
20	1					24
5	1					25
14	1					26
25	1					27
2	1					28
25	1					29
22	1					30
25	1					31
45	2					32
14	1					33
24	2					34
6	1					35
22	1					36
3	1					37
20	1					38
14	1					39
48	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	PACK CREEK RESERVOIR	DISTRIBUTION-UNATTEN	46.00	12.47	
2	PANGUITCH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	PARIETTE SUB	DISTRIBUTION-UNATTEN	69.00	24.94	
4	PARK CITY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	PARKSIDE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
6	PARKWAY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
7	PARLEYS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
8	PELICAN POINT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	PINE CANYON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
10	PINE CREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	PINNACLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	PLAIN CITY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
13	PLEASANT GROVE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
14	PLEASANT VIEW SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	PONY EXPRESS SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
16	PORTER ROCKWELL SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
17	PROMONTORY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	QUAIL CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	QUARRY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
20	QUICHAPA SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
21	RAINS SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
22	RANDOLPH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	RASMUSON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	RATTLESNAKE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
25	RED MOUNTAIN SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
26	REDWOOD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
27	RESEARCH PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	RICH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
29	RICHFIELD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	RICHMOND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	RIDGELAND SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
32	RITER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	ROCK CANYON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	ROCKVILLE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
35	ROCKY POINT	DISTRIBUTION-UNATTEN	138.00	13.20	
36	ROSE PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	ROYAL SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
38	SALINA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	SANDY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
40	SARATOGA SUB	DISTRIBUTION-UNATTEN	138.00	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 2016/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)	
4	1					1
5	1					2
14	1					3
42	2					4
60	2					5
50	2					6
16	2					7
6	1					8
55	2					9
2	1					10
14	1					11
22	1					12
25	1					13
14	1					14
60	2					15
30	1					16
2	1					17
4	1					18
60	2					19
4	1					20
15	1					21
2	1					22
1	3					23
14	1					24
12	1					25
45	2					26
45	2					27
5	1					28
22	2					29
11	1					30
40	2					31
20	1					32
5	1					33
4	1					34
30	1					35
24	3					36
	3					37
11	1					38
60	2					39
60	2					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 2016/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	SCIPIO SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	SCOFIELD RESERVOIR SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
3	SCOFIELD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	SECOND STREET SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	SEGO CANYON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	SEVEN MILE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	SHARON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
8	SHIVWITS SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
9	SHORELINE SUB	DISTRIBUTION-UNATTEN	138.00	13.20	
10	SIXTH SOUTH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	SKULL VALLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	SKYPARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	12.47
13	SNARR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	SNOWVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
15	SNYDERVILLE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
16	SOLDIER SUMMIT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	SOUTH JORDAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
18	SOUTH MILFORD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	SOUTH MOUNTAIN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
20	SOUTH OGDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	SOUTH PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
22	SOUTH WEBER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
23	SOUTHWEST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	SPANISH VALLEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	SPRINGDALE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
26	ST. JOHNS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
27	STANSBURY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	SUMMIT CREEK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
29	SUMMIT PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	SUNRISE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
31	SUTHERLAND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	TAMARISK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
33	TAYLOR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	THIEF CREEK SUB	DISTRIBUTION-UNATTEN	138.00	24.90	
35	THIRD WEST SUB	DISTRIBUTION-UNATTEN	138.00	13.20	
36	THIRTEENTH SOUTH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	TOOELE DEPOT SUB	DISTRIBUTION-UNATTEN	46.00	12.50	
38	TOQUERVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	34.50
39	UINTAH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	UNION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/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	3					1
1	1					2
1	3					3
13	2					4
14	1					5
	1					6
20	1					7
6	1					8
60	2					9
20	1					10
2	1					11
40	1					12
40	2					13
5	1					14
60	2					15
12	1					16
60	2					17
20	2					18
60	2					19
25	1					20
30	1					21
22	1					22
22	2					23
6	1					24
4	1					25
4	1					26
20	1					27
14	1					28
7	1					29
60	2					30
6	1					31
20	1					32
14	1					33
14	1					34
100	2					35
22	1					36
25	1					37
34	2					38
39	2					39
50	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/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	VALLEY CENTER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	VERMILLION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	VERNAL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	VICKERS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	VINEYARD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	WALLSBURG SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
7	WALNUT GROVE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
8	WARREN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
9	WASATCH STATE PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	WASHAKIE SUB	DISTRIBUTION-UNATTEN	138.00	4.16	
11	WELBY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	WELFARE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	WEST COMMERCIAL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	WEST JORDAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
15	WEST OGDEN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
16	WEST ROY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	WEST TEMPLE SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
18	WESTWATER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	WHITE ROCK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
20	WILLOWCREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	WILLOWRIDGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	WINCHESTER HILLS SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
23	WINKLEMAN SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
24	WOLF CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	WOOD CROSS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	WOODRUFF SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
27	TOTAL		19892.40	3502.63	105.44
28	Number of Substations-273				
29					
30	90TH SOUTH SUB	T/D-UNATTENDED	345.00	138.00	12.47
31	ANGEL SUB	T/D-UNATTENDED	138.00	12.47	46.00
32	BDO SUB	T/D-UNATTENDED	138.00	12.47	
33	BUTLERVILLE SUB	T/D-UNATTENDED	138.00	46.00	12.47
34	CENTENNIAL SUB	T/D-UNATTENDED	138.00	12.47	
35	COTTONWOOD SUB	T/D-UNATTENDED	138.00	12.47	46.00
36	DECADE SUB	T/D-UNATTENDED	138.00	12.47	
37	DUMAS SUB	T/D-UNATTENDED	138.00	12.47	
38	EMMA PARK SUB	T/D-UNATTENDED	138.00	12.47	
39	GROW SUB	T/D-UNATTENDED	138.00	12.47	46.00
40	HALE SUB	T/D-UNATTENDED	138.00	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 2016/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)	
22	1					1
3	1					2
33	2					3
2	1					4
25	1					5
13	1					6
30	1					7
30	1					8
2	3					9
14	1					10
42	2					11
10	1					12
22	1					13
28	1					14
60	2					15
25	1					16
60	3					17
5	1					18
30	1					19
1	1					20
14	1					21
4	1					22
	1					23
6	1					24
20	1					25
2	1					26
5597	373	2				27
						28
						29
1572	5					30
135	3					31
30	1					32
205	4					33
40	2					34
289	7					35
60	2					36
60	2					37
8	1					38
72	3					39
114	2					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 2016/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	HIGHLAND SUB	T/D-UNATTENDED	138.00	12.47	46.00
2	JORDAN SUB	T/D-UNATTENDED	138.00	46.00	12.47
3	JUDGE SUB	T/D-UNATTENDED	46.00	12.47	
4	MCCLELLAND SUB	T/D-UNATTENDED	138.00	46.00	12.47
5	MORTON COURT SUB	T/D-UNATTENDED	138.00	12.47	
6	OQUIRRH SUB	T/D-UNATTENDED	345.00	46.00	138.00
7	PARRISH SUB	T/D-UNATTENDED	138.00	12.47	46.00
8	PIONEER PLANT	T/D-UNATTENDED	138.00	12.47	
9	RIVERDALE SUB	T/D-UNATTENDED	138.00	46.00	12.47
10	SEVIER SUB	T/D-UNATTENDED	138.00	46.00	12.47
11	SILVER CREEK SUB	T/D-UNATTENDED	138.00	12.47	46.00
12	SOUTHEAST SUB	T/D-UNATTENDED	138.00	12.47	46.00
13	SYRACUSE SUB	T/D-UNATTENDED	345.00	46.00	138.00
14	TAYLORSVILLE SUB	T/D-UNATTENDED	138.00	46.00	12.47
15	TERMINAL SUB	T/D-UNATTENDED	345.00	46.00	138.00
16	TIMP SUB	T/D-UNATTENDED	138.00	46.00	12.47
17	TOOELE SUB	T/D-UNATTENDED	138.00	46.00	12.47
18	TRI CITY SUB	T/D-UNATTENDED	138.00	12.47	
19	WEST VALLEY SUB	T/D-UNATTENDED	138.00	12.47	
20	WESTFIELD SUB	T/D-UNATTENDED	138.00	12.47	
21	TOTAL		5014.00	914.46	860.70
22	Number of Substations-31				
23					
24	EMERY SUB	TRANSMISSION-ATTENDE	345.00	138.00	69.00
25	GADSBY SUB	TRANSMISSION-ATTENDE	138.00	46.00	
26	ABAJO SUB	TRANSMISSION-UNATTEN	138.00	69.00	
27	ASHLEY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
28	BARNEY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
29	BEN LOMOND SUB	TRANSMISSION-UNATTEN	345.00	230.00	138.00
30	BLACK ROCK SUB	TRANSMISSION-UNATTEN	230.00	69.00	
31	BLACKHAWK SUB	TRANSMISSION-UNATTEN	138.00	69.00	46.00
32	CAMERON SUB	TRANSMISSION-UNATTEN	138.00	46.00	
33	CAMP WILLIAMS SUB	TRANSMISSION-UNATTEN	345.00	138.00	12.47
34	CLOVER SUB	TRANSMISSION-UNATTEN	345.00	138.00	14.40
35	COLUMBIA SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
36	CRANER FLAT SUB	TRANSMISSION-UNATTEN	138.00	12.47	
37	CROYDON SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
38	CUTLER SUB	TRANSMISSION-UNATTEN	138.00	46.00	
39	EL MONTE SUB	TRANSMISSION-UNATTEN	138.00	46.00	
40	GARKANE SUB	TRANSMISSION-UNATTEN	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.
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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.
97	2					1
164	2					2
22	1					3
340	3					4
65	2					5
835	4	1				6
97	2					7
30	1					8
180	3					9
34	4					10
100	2					11
50	2					12
600	5					13
358	4					14
1108	6	2				15
130	2					16
249	3					17
30	1					18
30	1					19
20	1					20
7124	83	3				21
						22
						23
783	13					24
318	2					25
67	1					26
133	2					27
100	1					28
1813	5					29
75	1					30
100	2					31
25	4					32
169	2					33
448	1					34
71	2					35
40	2					36
81	2					37
50	1					38
312	3					39
33	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 2016/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	GREEN CANYON SUB	TRANSMISSION-UNATTEN	138.00	46.00	
2	GRINDING SUB	TRANSMISSION-UNATTEN	138.00	13.80	
3	HELPER SUB	TRANSMISSION-UNATTEN	138.00	46.00	
4	HONEYVILLE SUB	TRANSMISSION-UNATTEN	138.00	46.00	
5	HORSESHOE SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
6	HUNTINGTON SUB	TRANSMISSION-UNATTEN	345.00	138.00	24.90
7	JERUSALEM SUB	TRANSMISSION-UNATTEN	138.00	46.00	
8	LAMPO SUB	TRANSMISSION-UNATTEN	138.00	46.00	
9	MATHINGTON SUB	TRANSMISSION-UNATTEN	138.00	46.00	13.20
10	MCFADDEN SUB	TRANSMISSION-UNATTEN	138.00	46.00	
11	MIDDLETON SUB	TRANSMISSION-UNATTEN	138.00	69.00	34.50
12	MIDVALLEY SUB	TRANSMISSION-UNATTEN	345.00	138.00	
13	MIDWAY CITY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
14	MINERAL PRODUCTS SUB	TRANSMISSION-UNATTEN	69.00	46.00	
15	MOAB SUB	TRANSMISSION-UNATTEN	138.00	69.00	
16	NEBO SUB	TRANSMISSION-UNATTEN	138.00	46.00	
17	PAROWAN VALLEY SUB	TRANSMISSION-UNATTEN	230.00	138.00	34.50
18	PAVANT SUB	TRANSMISSION-UNATTEN	230.00	46.00	
19	PINTO SUB	TRANSMISSION-UNATTEN	345.00	138.00	69.00
20	RED BUTTE SUB	TRANSMISSION-UNATTEN	345.00	138.00	
21	SIGURD SUB	TRANSMISSION-UNATTEN	345.00	230.00	138.00
22	SMITHFIELD SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
23	SPANISH FORK SUB	TRANSMISSION-UNATTEN	345.00	138.00	46.00
24	ST GEORGE SUB	TRANSMISSION-UNATTEN	138.00	16.50	
25	THREE PEAKS SUB	TRANSMISSION-UNATTEN	345.00	138.00	
26	WEST CEDAR SUB	TRANSMISSION-UNATTEN	230.00	138.00	34.50
27	TOTAL		8441.00	3377.77	724.35
28	Number of Substations-43				
29					
30	WASHINGTON				
31	ATTALIA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	BOWMAN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	CASCADE KRAFT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	4.16
34	CLINTON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
35	DAYTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	DODD ROAD SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
37	GRANDVIEW SUB	DISTRIBUTION-UNATTEN	115.00	12.47	69.00
38	HOPLAND SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
39	NACHES SUB	DISTRIBUTION-UNATTEN	115.00	12.00	
40	NOB HILL 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) (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.
67	2					1
225	3					2
142	2					3
35	1					4
80	2					5
270	4					6
67	1					7
75	1					8
160	5	1				9
45	1					10
141	4					11
900	2					12
67	1					13
12	1					14
67	1					15
67	1					16
138	2					17
133	2					18
258	3					19
414	2					20
1124	6					21
63	2					22
1017	5					23
100	3	1				24
450	1					25
262	3					26
10997	106	2				27
						28
						29
						30
25	1					31
45	2					32
118	6					33
25	1					34
23	2					35
25	4					36
42	2					37
50	2					38
25	1					39
42	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	NORTH PARK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
2	ORCHARD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
3	PACIFIC SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
4	POMEROY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
5	PROSPECT POINT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	PUNKIN CENTER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
7	RIVER ROAD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
8	SELAH SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
9	SULPHUR CREEK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
10	SUNNYSIDE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
11	TIETON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	34.50
12	TOPPENISH SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
13	TOUCHET SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	VOELKER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
15	WAITSBURG SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	WAPATO SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
17	WENAS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
18	WHITE SWAN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
19	WILEY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
20	TOTAL		2921.00	369.49	107.66
21	Number of Substations-29				
22					
23	CENTRAL SUB	T/D-UNATTENDED	69.00	12.47	
24	MILL CREEK SUB	T/D-UNATTENDED	69.00	12.47	
25	UNION GAP SUB	T/D-UNATTENDED	230.00	115.00	12.47
26	TOTAL		368.00	139.94	12.47
27	Number of Substations-3				
28					
29	OUTLOOK SUB	TRANSMISSION-UNATTEN	230.00	115.00	
30	PASCO SUB	TRANSMISSION-UNATTEN	115.00	69.00	7.20
31	POMONA HEIGHTS SUB	TRANSMISSION-UNATTEN	230.00	115.00	13.20
32	WALLA WALLA 230kV SUB	TRANSMISSION-UNATTEN	230.00	69.00	
33	WALLULA SUB	TRANSMISSION-UNATTEN	230.00	69.00	
34	WINE COUNTRY SUB	TRANSMISSION-UNATTEN	230.00	115.00	
35	TOTAL		1265.00	552.00	20.40
36	Number of Substations-6				
37					
38	WYOMING				
39	ANTELOPE MINE SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
40	ARROWHEAD SUB	DISTRIBUTION-UNATTEN	230.00	34.50	

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
50	2					2
28	3					3
9	1					4
40	2					5
20	2					6
76	5					7
45	2					8
25	1					9
45	2					10
29	2					11
50	2					12
6	1					13
25	1					14
9	1					15
45	2					16
25	2					17
22	2					18
45	2					19
1059	60					20
						21
						22
14	1					23
45	2					24
595	5					25
654	8					26
						27
						28
125	1					29
39	9					30
325	3					31
300	2					32
120	2					33
250	1					34
1159	18					35
						36
						37
						38
25	1					39
150	2					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 2016/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	ASTLE STREET	DISTRIBUTION-UNATTEN	34.50	13.20	
2	BAILEY DOME SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
3	BAR NUNN	DISTRIBUTION-UNATTEN	116.00	13.20	
4	BAR X SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
5	BIG MUDDY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	BIG PINEY SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
7	BLACKS FORK SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
8	BRIDGER PUMP SUB	DISTRIBUTION-UNATTEN	230.00	34.50	13.20
9	BRYAN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
10	BUFFALO TOWN SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
11	BYRON SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
12	CASSA SUB	DISTRIBUTION-UNATTEN	57.00	20.80	12.47
13	CENTER STREET SUB	DISTRIBUTION-UNATTEN	115.00	4.16	
14	CHAPMAN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	CHUKAR SUB	DISTRIBUTION-UNATTEN	12.47	4.16	
16	CHURCH AND DWIGHT SUB	DISTRIBUTION-UNATTEN	34.50	0.48	
17	COKEVILLE SUB	DISTRIBUTION-UNATTEN	46.00	24.90	
18	COLUMBIA-GENEVA SUB	DISTRIBUTION-UNATTEN	230.00	13.80	
19	COMMUNITY PARK SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
20	CROOKS GAP SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
21	DEER CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	DJ COAL MINE SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
23	DOUGLAS SUB	DISTRIBUTION-UNATTEN	57.00	2.30	
24	DRY FORK SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
25	ELK BASIN SUB	DISTRIBUTION-UNATTEN	34.50	7.20	
26	EMIGRANT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
27	EVANS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
28	EVANSTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
29	FORT CASPER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	FORT SANDERS SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
31	FRANNIE SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
32	FRONTIER SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
33	GARLAND SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
34	GLENDO SUB	DISTRIBUTION-UNATTEN	57.00	4.16	
35	GRASS CREEK SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
36	GREAT DIVIDE SUB	DISTRIBUTION-UNATTEN	115.00	34.50	
37	GREYBULL SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
38	HANNA SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
39	JACKALOPE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
40	KEMMERER SUB	DISTRIBUTION-UNATTEN	69.00	24.90	

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)	
12	1					1
2	1					2
30	1					3
25	1					4
7	1					5
14	1					6
150	2					7
73	4					8
25	1					9
2	3					10
2	3					11
2	6					12
12	1					13
4	1					14
1	3					15
3	2					16
4	1					17
45	2					18
45	2					19
5	3					20
9	1					21
12	1					22
6	3					23
9	1					24
5	1					25
12	1					26
9	1					27
40	2					28
28	1					29
20	1					30
50	2					31
6	1					32
45	2					33
3	4					34
25	1					35
20	1					36
3	1					37
6	1					38
25	1					39
10	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 2016/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	KIRBY CREEK PUMPING STATION	DISTRIBUTION-UNATTEN	115.00	2.40	
2	KIRBY CREEK SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
3	LANDER SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
4	LARAMIE SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
5	LATHAM SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
6	LINCH SUB	DISTRIBUTION-UNATTEN	69.00	13.80	
7	LITTLE MOUNTAIN SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
8	LOVELL SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
9	MILL IRON SUB	DISTRIBUTION-UNATTEN	34.50	13.80	
10	MILLS SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
11	MURPHY DOME SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
12	NUGGETT SUB	DISTRIBUTION-UNATTEN	69.00	7.20	
13	OPAL SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
14	ORIN SUB	DISTRIBUTION-UNATTEN	57.00	7.20	
15	ORPHA SUB	DISTRIBUTION-UNATTEN	57.00	7.20	
16	PARADISE SUB	DISTRIBUTION-UNATTEN	69.00	25.00	
17	PARCO SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
18	PINEDALE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
19	PITCHFORK SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
20	POISON SPIDER SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
21	POLECAT SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
22	RAINBOW SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
23	RAVEN SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
24	RED BUTTE SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
25	REFINERY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
26	SAGE HILL SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
27	SHOSHONI SUB	DISTRIBUTION-UNATTEN	34.50	2.40	
28	SLATE CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
29	SOUTH CODY SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
30	SOUTH ELK BASIN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
31	SOUTH TRONA SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
32	SPRING CREEK SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
33	SVILAR SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
34	TEN MILE STEP DOWN SUB	DISTRIBUTION-UNATTEN	34.50	12.50	
35	TEN MILE SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
36	THERMOPOLIS TOWN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
37	THUNDER CREEK SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
38	VETERANS SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
39	WERTZ-SINCLAIR SUB	DISTRIBUTION-UNATTEN	57.00	4.16	12.50
40	WEST ADAMS SUB	DISTRIBUTION-UNATTEN	34.50	4.16	

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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.
3	3					1
2	3					2
25	2					3
50	2					4
25	1					5
12	1					6
20	1					7
4	1					8
12	1					9
1	3					10
5	1					11
	1					12
8	1					13
1	1					14
3	3					15
30	1					16
5	1					17
20	1					18
17	9	2				19
3	1					20
1	3					21
12	1					22
200	2					23
30	1					24
45	2					25
6	1					26
2	3					27
1	1					28
14	3	1				29
2	6					30
150	2					31
28	1					32
2	3					33
5	1					34
12	1					35
5	1					36
9	1					37
25	2					38
2	6					39
3	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WESTVACO SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
2	WORLAND TOWN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
3	WYOPO SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
4	TOTAL		7896.27	1339.66	38.17
5	Number of Substations-85				
6					
7	BUFFALO SUB	T/D-UNATTENDED	230.00	20.80	
8	ELK HORN SUB	T/D-UNATTENDED	115.00	12.47	
9	FIREHOLE SUB	T/D-UNATTENDED	230.00	34.50	
10	HILLTOP SUB	T/D-UNATTENDED	115.00	34.50	20.80
11	LABARGE SUB	T/D-UNATTENDED	69.00	24.90	
12	POINT OF ROCKS SUB	T/D-UNATTENDED	230.00	34.50	
13	RIVERTON 230 SUB	T/D-UNATTENDED	230.00	12.47	34.50
14	YELLOWCAKE SUB	T/D-UNATTENDED	230.00	34.50	
15	TOTAL		1449.00	208.64	55.30
16	Number of Substations-8				
17					
18	DAVE JOHNSTON PLANT/SUB	TRANSMISSION-ATTENDE	230.00	115.00	69.00
19	JIM BRIDGER 345kV SUB	TRANSMISSION-ATTENDE	345.00	230.00	34.50
20	NAUGHTON SUB	TRANSMISSION-ATTENDE	230.00	138.00	69.00
21	BAIROIL SUB	TRANSMISSION-UNATTEN	115.00	34.50	57.00
22	CASPER SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
23	CHAPPEL CREEK SUB	TRANSMISSION-UNATTEN	230.00	69.00	
24	CHIMNEY BUTTE SUB	TRANSMISSION-UNATTEN	230.00	69.00	
25	FOOTE CREEK WIND FARM	TRANSMISSION-UNATTEN	230.00	34.50	
26	GLENDO AUTO SUB	TRANSMISSION-UNATTEN	69.00	57.00	
27	MANSFACE SUB	TRANSMISSION-UNATTEN	230.00	34.50	
28	MIDWEST SUB	TRANSMISSION-UNATTEN	230.00	69.00	34.50
29	MINERS SUB	TRANSMISSION-UNATTEN	230.00	34.50	9.70
30	MUSTANG SUB	TRANSMISSION-UNATTEN	230.00	115.00	
31	OREGON BASIN SUB	TRANSMISSION-UNATTEN	230.00	34.50	69.00
32	PLATTE SUB	TRANSMISSION-UNATTEN	230.00	115.00	34.50
33	RAILROAD SUB	TRANSMISSION-UNATTEN	230.00	138.00	
34	ROCK SPRINGS 230 SUB	TRANSMISSION-UNATTEN	230.00	34.50	
35	SAGE SUB	TRANSMISSION-UNATTEN	69.00	46.00	
36	STANDPIPE SUB	TRANSMISSION-UNATTEN	230.00	12.47	
37	THERMOPOLIS SUB	TRANSMISSION-UNATTEN	230.00	115.00	
38	TOTAL		4278.00	1610.47	446.20
39	Number of Substations-20				
40					

SUBSTATIONS (Continued)

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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)	
25	1					1
5	1					2
20	1	1				3
1831	154	4				4
						5
						6
20	1					7
25	1					8
50	2					9
45	2	1				10
8	6					11
25	1					12
74	4					13
25	1					14
272	18	1				15
						16
						17
336	4					18
703	7					19
661	4					20
53	3					21
575	4					22
67	1					23
75	1					24
196	2					25
15	2					26
20	1					27
157	3					28
20	1					29
100	1					30
65	2					31
140	3					32
400	1					33
50	2					34
23	1					35
75	1					36
175	2					37
3906	46					38
						39
						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 2016/Q4

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	CALIFORNIA				
2	Distribution - 42				
3	T/D - 2				
4	Transmission - 5				
5					
6	IDAHO				
7	Distribution - 65				
8	T/D - 5				
9	Transmission - 17				
10					
11	MONTANA				
12	Transmission - 3				
13					
14	OREGON				
15	Distribution - 180				
16	T/D - 12				
17	Transmission - 27				
18					
19	UTAH				
20	Distribution - 273				
21	T/D - 31				
22	Transmission - 43				
23					
24	WASHINGTON				
25	Distribution - 29				
26	T/D - 3				
27	Transmission - 6				
28					
29	WYOMING				
30	Distribution - 85				
31	T/D - 8				
32	Transmission - 20				
33					
34	ALL STATES				
35	Distribution - 674				
36	T/D - 61				
37	Transmission - 121				
38					
39					
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 2016/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
323						2
130						3
725						4
						5
						6
736						7
344						8
5081						9
						10
						11
200						12
						13
						14
4615						15
1260						16
7492						17
						18
						19
5597						20
7124						21
10997						22
						23
						24
1059						25
654						26
1159						27
						28
						29
1831						30
272						31
3906						32
						33
						34
14161						35
9784						36
29560						37
						38
						39
						40

Schedule Page: 426.3 Line No.: 18 Column: a

The Antelope 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: 426.3 Line No.: 20 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.: 25 Column: a

The Goshen 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.: 27 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.: 28 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.: 32 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.: 38 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.: 39 Column: a

The Colstrip 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: 426.9 Line No.: 10 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.: 14 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.: 19 Column: a

The Malin 500kV Substation is jointly owned by PacifiCorp, BPA and Portland General Electric Company. Ownership and operations and maintenance costs vary by type of asset defined in the Joint Ownership and Operating Agreement.

Schedule Page: 426.9 Line No.: 20 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: 426.19 Line No.: 32 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.: 18 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.: 19 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 2016/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	Bridger Coal Company	151,501	185,190,751
3	Coal purchases	Trapper Mining Inc.	151,501	11,194,071
4	Administrative services under the IASA	BHE		5,820,689
5	Administrative services under the IASA	MEC		3,199,195
6	Administrative services under the IASA	NV Energy, Inc.	107,923	364,975
7	Administrative services under the IASA	Kern River Gas Transmission Company	923	9,280
8	Gas transportation services and encroachment			
9	agreement for Sigurd to Red Butte	Kern River Gas Transmission Company	547,571	3,390,978
10	Rail services and right-of-way fees	BNSF Railway Company	151,507,567,589	37,262,344
11	Employee relocation services	HomeServices of America, Inc.		1,412,541
12	Banking services and financial transactions			
13	related to energy hedging activity	Wells Fargo & Company		1,263,672
14	Banking services	U.S. Bancorp		528,971
15	Computer hardware and software and computer			
16	systems maintenance and support services	International Business Machines Corp	165,909,921,935	2,155,311
17	Lubricating oil and grease products	Phillips 66 Company		750,859
18	Equipment rental	Deere & Company	512,514	386,710
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Information technology and administrative			
22	support services	Bridger Coal Company		980,399
23	Joint use services	Charter Communications, Inc.	416,454,593	946,509
24	Administrative services under the IASA	MEC		927,942
25	Administrative services under the IASA	BHE U.S. Transmission, LLC		1,496,460
26	Administrative services under the IASA	MTL Canyon Holdings, LLC		419,828
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				

Schedule Page: 429 Line No.: 4 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 and regulatory groups. The legislative and 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 and 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.: 4 Column: c

Accounts charged from BHE: 107, 426.1, 426.4, 426.5, 923 and 928.

Schedule Page: 429 Line No.: 4 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.: 5 Column: b

This footnote applies to all occurrences of "MEC" on page 429. Complete name is MidAmerican Energy Company.

Schedule Page: 429 Line No.: 5 Column: c

Accounts charged from MEC: 107, 426.4, 426.5 and 923.

Schedule Page: 429 Line No.: 5 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.: 6 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.: 7 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.: 10 Column: d

Non-power goods or services provided by BNSF Railway Company are as follows:

Rail services	$37,213,748
Right-of-way fees	48,596
	$37,262,344

Included in the rail services are amounts related to a jointly-owned plant that are paid indirectly to BNSF Railway Company.

Schedule Page: 429 Line No.: 11 Column: c

Accounts charged from HomeServices of America, Inc.: 506, 535, 539, 548, 549, 557, 560, 561.2, 570, 580, 581, 590, 592, 593, 903, 908 and 921.

Schedule Page: 429 Line No.: 13 Column: c

Accounts charged from Wells Fargo & Company: 186, 228.3, 419, 426.5, 427, 431, 501, 547, 548, 903, 921 and 928.

Schedule Page: 429 Line No.: 13 Column: d

Non-power goods or services provided by Wells Fargo & Company are as follows:

Banking services	$1,128,022
Financial transactions related to energy hedging activity	135,650
	$1,263,672

Schedule Page: 429 Line No.: 14 Column: c

Accounts charged from U.S. Bancorp: 186, 419, 427, 431, 537, 557, 589, 903, 920, 928 and 930.2.

Schedule Page: 429 Line No.: 16 Column: b

Complete name is International Business Machines Corporation.

Schedule Page: 429 Line No.: 17 Column: c

Accounts charged from Phillips 66 Company: 154, 500, 501, 502, 506, 511, 512, 513, 514, 539, 548, 553, 557, 562, 570, 571, 582, 583, 592 and 593.

Schedule Page: 429 Line No.: 22 Column: c

Accounts charged to Bridger Coal Company: 426.5, 501, 557, 923 and 930.2.

Schedule Page: 429 Line No.: 24 Column: c

Accounts charged to MEC: 426.5, 556, 557, 580, 588, 590, 903, 920 and 921.

Schedule Page: 429 Line No.: 24 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.: 25 Column: c

Accounts charged to BHE U.S. Transmission, LLC: 426.5, 560, 580, 920 and 921.

Schedule Page: 429 Line No.: 25 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.: 26 Column: c

Accounts charged to MTL Canyon Holdings, LLC: 560, 580, 920 and 921.

Schedule Page: 429 Line No.: 26 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.

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