ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W. North Temple, Suite 310
Salt Lake City, Utah 84116

May 29, 2019

VIA ELECTRONIC FILING

Public Service Commission
Heber M. Wells Building, Fourth Floor
P. O. Box 45585
Salt Lake City, Utah 84145

Attention: Gary Widerburg
Commission Secretary

RE: Docket No. 19-999-01
FERC Form No. 1

PacifiCorp (d.b.a. Rocky Mountain Power) submits for electronic filing PacifiCorp's annual FERC Form No. 1 report for the year ended December 31, 2018.

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

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

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

Please direct any informal questions to Jana Saba, Regulatory Manager, at (801) 220-2823.

Sincerely,

Joelle Steward
Vice President, Regulation

Enclosure

CERTIFICATE OF SERVICE

I hereby certify that on May 29, 2019, a true and correct copy of the foregoing was served by electronic mail and overnight delivery to the following:

Utah Office of Consumer Services
Cheryl Murray
Utah Office of Consumer Services
160 East 300 South, 2nd Floor
Salt Lake City, UT 84111
cmurray@utah.gov

Division of Public Utilities
Division of Public Utilities
160 East 300 South, 4th Floor
Salt Lake City, UT 84111
dpudatarequest@utah.gov

Katie Savarin

Katie Savarin
Coordinator, Regulatory Operations

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

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

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
PacifiCorp	**End of** 2018/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 1,168 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 168 hours per response.

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

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

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

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

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

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

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

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

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

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

General Penalties

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

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

IDENTIFICATION

01 Exact Legal Name of Respondent PacifiCorp	02 Year/Period of Report End of 2018/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 825 N.E. Multnomah Street, Suite 1900, Portland, OR 97232	
05 Name of Contact Person Mark Reis	06 Title of Contact Person Corporate Accounting Director
07 Address of Contact Person *(Street, City, State, Zip Code)* 825 N.E. Multnomah Street, Suite 1900, Portland, OR 97232	

08 Telephone of Contact Person, *Including Area Code* (503) 813-6859	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* / /

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name Nikki L. Kobliha	03 Signature Nikki L. Kobliha (Signature on file)	04 Date Signed *(Mo, Da, Yr)* 04/12/2019
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 PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/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".

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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 1.9 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., Mr. Walter Scott, Jr., a member of BHE's Board of Directors (along with his family members and related or affiliated entities) and Mr. Gregory E. Abel, BHE's Executive Chairman, beneficially own 90.9%, 8.1% and 1.0%, respectively, of BHE's voting common stock.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Energy West Mining Company	Mining	100.00	
2	Fossil Rock Fuels, LLC	Mining	100.00	
3	Glenrock Coal Company	Mining	100.00	
4	Interwest Mining Company	Management services	100.00	
5	Pacific Minerals, Inc.	Management services	100.00	
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. As of December 31, 2018, the Foundation's two 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 2018/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			
2	Chairman of the Board of Directors		
3	and Chief Executive Officer, PacifiCorp	William J. Fehrman	
4			
5	President and Chief Executive Officer,		
6	Pacific Power	Stefan A. Bird	355,000
7			
8	President and Chief Executive Officer,		
9	Rocky Mountain Power	Gary W. Hoogeveen	315,570
10			
11	Vice President, Chief Financial Officer and Treasurer,		
12	PacifiCorp	Nikki L. Kobliha	224,510
13			
14	Former Chairman of the Board of Directors		
15	and Chief Executive Officer, PacifiCorp	Gregory E. Abel	
16			
17	Former President and Chief Executive Officer,		
18	Rocky Mountain Power	Cindy A. Crane	355,000
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Schedule Page: 104 Line No.: 1 Column: c

PacifiCorp sets forth compensation information for its "named executive officers" for the year ended December 31, 2018, 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 C.F.R. §388.107(d)(f).

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

On January 10, 2018, William J. Fehrman was elected as PacifiCorp's Chairman of the Board of Directors and Chief Executive Officer and Gregory E. Abel resigned as PacifiCorp's Chairman of the Board of Directors and Chief Executive Officer.

William J. Fehrman received no direct compensation from PacifiCorp. PacifiCorp reimbursed its indirect parent company, Berkshire Hathaway Energy Company ("BHE"), for the cost of Mr. Fehrman’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. For further information on executive compensation, refer to BHE’s Annual Report on Form 10-K, for the year ended December 31, 2018.

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

Gary W. Hoogeveen succeeded Cindy A. Crane as president and chief executive officer of Rocky Mountain Power and was elected as a director of PacifiCorp during 2018. For further information, refer to Item 13 in Important Changes During the Year in this Form No. 1.

Schedule Page: 104 Line No.: 15 Column: b

Gregory E. Abel received no direct compensation from PacifiCorp. During 2018, PacifiCorp did not incur reimbursements to 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. For further information on executive compensation, refer to BHE’s Annual Report on Form 10-K, for the year ended December 31, 2018.

Schedule Page: 104 Line No.: 18 Column: b

Cindy A. Crane, former president and chief executive officer of Rocky Mountain Power, resigned as director and employee of PacifiCorp on February 4, 2019. 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 2018/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, 2018:	
2		
3	William J. Fehrman	
4	(Chairman of the Board of Directors and CEO, PacifiCorp)	666 Grand Avenue, 27th Floor, Des Moines, IA 50309
5		
6	Stefan A. Bird	
7	(President and CEO, Pacific Power)	825 N.E. Multnomah Street, Suite 2000, Portland, OR 97232
8		
9	Gary W. Hoogeveen	
10	(President and CEO, Rocky Mountain Power)	1407 West North Temple, Suite 310, Salt Lake City, UT 84116
11		
12	Nikki L. Kobliha	
13	(VP, CFO and Treasurer, PacifiCorp)	825 N.E. Multnomah Street, Suite 1900, Portland, OR 97232
14		
15	Patrick J. Goodman	666 Grand Avenue, 27th Floor, Des Moines, IA 50309
16		
17	Natalie L. Hocken	825 N.E. Multnomah Street, Suite 2000, Portland, OR 97232
18		
19	Cindy A. Crane	1407 West North Temple, Suite 310, Salt Lake City, UT 84116
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Schedule Page: 105 Line No.: 3 Column: a

On January 10, 2018, Gregory E. Abel resigned as PacifiCorp's Chairman of the Board of Directors and Chief Executive Officer and William J. Fehrman was elected as PacifiCorp's Chairman of the Board of Directors and Chief Executive Officer.

Schedule Page: 105 Line No.: 9 Column: a

Gary W. Hoogeveen succeeded Cindy A. Crane as president and chief executive officer of Rocky Mountain Power and was elected as a director of PacifiCorp during 2018. For further information, refer to Item 13 in Important Changes During the Year in this Form No. 1.

Schedule Page: 105 Line No.: 19 Column: a

Cindy A. Crane, former president and chief executive officer of Rocky Mountain Power, resigned as director and employee of PacifiCorp on February 4, 2019. 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 2018/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 2018/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	20180323-5024	03/23/2018	ER11-3643		
2	20180330-5118	03/30/2018	ER18-1243		
3	20180515-5352	05/15/2018	ER11-3643		
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Schedule Page: 1061 Line No.: 1 Column: d

PacifiCorp submits tariff filing per 35.19a(b): FERC Audit Refund Report to be effective N/A under FERC Docket No. ER11-3643

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

PacifiCorp's Volume No. 11 Open Access Transmission Tariff

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

PacifiCorp submits tariff filing per 35.13(a)(2)(iii): OATT Revised Attachment H-1 (Revised Depreciation Rates 2018) to be effective 6/1/2018 under FERC Docket No. ER18-1243

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

PacifiCorp's Volume No. 11 Open Access Transmission Tariff

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

Transmission Formula Rate Annual Update Informational Filing of PacifiCorp under FERC Docket No. ER11-3643

Schedule Page: 1061 Line No.: 3 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 2018/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
1	204-207	Electric Plant in Service	(b)	5
2	204-207	Electric Plant in Service	(b)	46
3	204-207	Electric Plant in Service	(g)	46
4	204-207	Electric Plant in Service	(b)	75
5	204-207	Electric Plant in Service	(g)	75
6	204-207	Electric Plant in Service	(b)	99
7	204-207	Electric Plant in Service	(g)	99
8	204-207	Electric Plant in Service	(b)	104
9	204-207	Electric Plant in Service	(g)	104
10	219	Accum. Prov. for Depr. of Electric Utility Plant	(c)	20
11	219	Accum. Prov. for Depr. of Electric Utility Plant	(c)	22
12	219	Accum. Prov. for Depr. of Electric Utility Plant	(c)	24
13	219	Accum. Prov. for Depr. of Electric Utility Plant	(c)	25
14	219	Accum. Prov. for Depr. of Electric Utility Plant	(c)	26
15	219	Accum. Prov. for Depr. of Electric Utility Plant	(c)	28
16	219	Accum. Prov. for Depr. of Electric Utility Plant	(c)	29
17	320-323	Electric Operation and Maintenance Expenses	(b)	185
18	320-323	Electric Operation and Maintenance Expenses	(b)	197
19	336-337	Depreciation and Amortization of Electric Plant	(d)	1
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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)			
Ririe	07/12/2018	07/12/2028	—
Oregon(3)			
Arlington	04/17/2018	04/17/2023	3.5%
Bend	12/21/2018	06/30/2019	5.0%
Chiloquin	05/09/2018	05/09/2028	3.5%
Eagle Point	07/23/2018	07/23/2023	7.0%
Lyons	10/24/2018	10/24/2038	3.5%
Merrill	03/16/2018	03/16/2028	5.0%
Monroe	09/12/2018	09/12/2038	5.0%
Stanfield	11/17/2018	03/26/2032	7.0%
Talent	04/20/2018	04/20/2028	7.0%
Utah(4)			
Bluff	12/20/2018	12/20/2038	—
Brigham City	05/01/2018	05/01/2028	—
Cedar Highlands	06/01/2018	06/01/2028	—
Clinton	05/01/2018	05/01/2028	—
Deweyville	12/01/2018	12/01/2028	—
Farr West	09/01/2018	09/01/2028	—
Fruit Heights	07/19/2018	07/19/2038	—
Herriman	08/01/2018	08/01/2038	—
Iron County	11/01/2018	11/01/2033	—
Lehi	06/11/2018	06/11/2023	—
Minersville	04/16/2018	04/16/2028	—
Naples	05/01/2018	05/01/2028	—
Roy	04/01/2018	04/01/2028	—
Sunset	04/15/2018	04/15/2028	—
Taylorsville	08/18/2018	08/18/2028	—
Washington Terrace	12/21/2018	12/21/2028	—
Washington(4)			
None			
Wyoming(5)			
Casper	01/01/2018	01/01/2038	7.0%
Evanston	02/27/2018	02/27/2043	1.0%

(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. The franchise agreement for Bend, Oregon is an extension of the agreement effective August 31, 2007, for which the agreement is expected to be modified by the expiration date.

(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. The franchise agreement fee for Casper, Wyoming is expected to be reduced to 5.0%, after four years.

ITEM 2.

None.

ITEM 3.

None.

ITEM 4.

None.

ITEM 5.

In May 2018, PacifiCorp filed an update to its 2017 Integrated Resource Plan ("IRP") with state commissions, originally filed in April 2017. The updated IRP which discusses the Energy Vision 2020 project ("Energy Vision 2020"), includes investments in renewable energy resources, upgrades to PacifiCorp's existing wind fleet, energy efficiency measures to meet future customer needs and incorporates building an additional transmission line segment to facilitate the expansion of wind generation. Collectively, these resources contribute to meeting the capacity need identified in PacifiCorp's updated load-and-balance and are on track to be in service by the end of 2020. The transmission segment included in Energy Vision 2020 is part of the Energy Gateway Transmission expansion program and PacifiCorp plans to construct 140 miles of 500kV transmission line between Aeolus and Bridger/Anticline, to be placed in-service in 2020.

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, 2018.

ITEM 6.

Short-term Debt

Regulatory authorities limit PacifiCorp to $1.5 billion of short-term debt. As of December 31, 2018, PacifiCorp had $30 million of short-term debt outstanding at a weighted average interest rate of 2.85%.

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:

- Federal Energy Regulatory Commission – Docket No. ES18-3-000, dated December 20, 2017, letter order effective January 1, 2018 through December 31, 2019.
- Idaho Public Utilities Commission ("IPUC") – Case No. PAC-E-16-03, Order No. 33476, dated March 4, 2016, effective through April 30, 2021.
- Oregon Public Utility Commission ("OPUC") – Docket No. UF-4120, Order No. 98-158, dated April 16, 1998.
- Washington Utilities and Transportation Commission ("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

In March 2019, PacifiCorp issued $400 million of its 3.500% First Mortgage Bonds due June 2029 and $600 million of its 4.150% First Mortgage Bonds due February 2050. PacifiCorp used a portion of the net proceeds to repay short-term debt that was partially incurred to repay all of PacifiCorp's $350 million 5.50% First Mortgage Bonds due January 2019. PacifiCorp intends to use the remaining net proceeds to fund capital expenditures and for general corporate purposes.

PacifiCorp had regulatory authority from the OPUC and the IPUC to issue $2.0 billion of long-term debt, as of December 31, 2018. PacifiCorp must make a notice filing with the WUTC prior to any future issuance. As of December 31, 2018, PacifiCorp currently had an effective shelf registration statement with the United States Securities Exchange Commission to issue up to $2.0 billion additional first mortgage bonds through October 2021.

State commission authorizations for the above issuance and future issuances are as follows:

- IPUC – Case No. PAC-E-18-10, Order No. 34205, dated December 7, 2018, effective through September 30, 2023.
- OPUC – Docket No. UF-4304, Order No. 18-452, dated December 4, 2018.

In July 2018, PacifiCorp issued $600 million of its 4.125% First Mortgage Bonds due January 2049. PacifiCorp used a portion of the net proceeds to repay all of PacifiCorp's $500 million 5.65% First Mortgage Bonds due July 2018 and used the remaining net proceeds to fund capital expenditures and for general corporate purposes. State commission authorizations for this issuance are as follows:

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

PacifiCorp made repayments on long-term debt, excluding repayments for lease obligations, totaling $586 million during the year ended December 31, 2018.

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, 2018, PacifiCorp estimated it would be able to issue up to $10.3 billion of new first mortgage bonds under the most restrictive issuance test in the mortgage. Any issuances are subject to market conditions and amounts may be further limited by regulatory authorizations or commitments or by covenants and tests contained in other financing agreements. PacifiCorp also has the ability to release property from the lien of the mortgage on the basis of property additions, bond credits or deposits of cash.

For further discussion, refer to Note 7 of Notes to Financial Statements, in this Form No. 1.

ITEM 7.

None.

ITEM 8.

For the year ended December 31, 2018, 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)	1.86%	01/26/2018	$ 59,125
IBEW 57 Laramie (WY)	1.04%	06/26/2018	5,854
IBEW 57 Power Delivery (UT, ID & WY)	1.83%	01/26/2018	1,491,243
IBEW 57 Power Supply (UT, ID & WY)	1.86%	01/26/2018	694,211
IBEW 77 (WA)	2.10%	01/26/2018	24,084
IBEW 125 (OR, WA)	2.33%	01/26/2018	621,398
IBEW 125 (OR, WA)	0.20%	12/11/2018	51,038
IBEW 659 (OR, CA)	1.37%	04/26/2018	435,317
UWUA 127 (WY)	0.71%	09/26/2018	324,013
UWUA 197 (OR)	1.20%	05/26/2018	18,358
Total			$ 3,724,641

(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.

For the year ended December 31, 2018, Pacific Minerals, Inc., a wholly owned subsidiary of PacifiCorp, declared and paid a dividend of $18.0 million to PacifiCorp. In addition, Fossil Rock Fuels, LLC, a wholly owned subsidiary of PacifiCorp, distributed $5.4 million of dividends, consisting of $2.7 million unappropriated retained earnings distribution and $2.7 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, 2018, other than preferred and common stock dividends declared and paid.

ITEM 11.

(Reserved.)

ITEM 12.

None.

ITEM 13.

On February 4, 2019, Cindy A. Crane, former president and chief executive officer of Rocky Mountain Power, a division of PacifiCorp, resigned as director and employee of PacifiCorp.

During 2018, Gary W. Hoogeveen succeeded Cindy A. Crane as president and chief executive officer of Rocky Mountain Power. Mr. Hoogeveen was elected as a director of PacifiCorp on November 19, 2018.

On January 10, 2018, Gregory E. Abel resigned as PacifiCorp's Chairman of the Board of Directors and Chief Executive Officer and William J. Fehrman was elected as PacifiCorp's Chairman of the Board of Directors and Chief Executive Officer.

ITEM 14.

Not applicable.

Deloitte.

Deloitte & Touche LLP
U.S. Bancorp Tower
111 Southwest Fifth Avenue
Suite 3900
Portland, OR 97204-3642
USA

Tel:+1 503 222 1341
Fax:+1 503 224 2172
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, 2018, 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, 2018, 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 12, 2019

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 2018/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	28,425,063,446	27,861,824,875
3	Construction Work in Progress (107)	200-201	1,194,168,876	676,995,960
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		29,619,232,322	28,538,820,835
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	11,032,877,405	10,301,826,872
6	Net Utility Plant (Enter Total of line 4 less 5)		18,586,354,917	18,236,993,963
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)		18,586,354,917	18,236,993,963
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		13,578,986	13,710,649
19	(Less) Accum. Prov. for Depr. and Amort. (122)		3,149,894	3,045,138
20	Investments in Associated Companies (123)		69,928	69,928
21	Investment in Subsidiary Companies (123.1)	224-225	183,401,017	186,007,067
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)		95,479,061	97,005,097
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		14,919,564	5,835,163
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		2,565,604	766,962
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		306,864,266	300,349,728
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		20,006,166	4,805,006
36	Special Deposits (132-134)		0	9,003,656
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		49,330,121	8,735,365
39	Notes Receivable (141)		5,068,150	2,730,593
40	Customer Accounts Receivable (142)		426,619,902	419,318,429
41	Other Accounts Receivable (143)		48,930,705	46,887,023
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		7,691,154	9,773,266
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		628,710	73,462,590
45	Fuel Stock (151)	227	179,588,705	197,499,391
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	237,694,431	235,276,870
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		48,020,660	75,998,324
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		1,128,478	1,343,210
61	Accrued Utility Revenues (173)		229,061,000	255,154,000
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		27,458,631	8,996,262
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		2,565,604	766,962
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)		1,263,278,901	1,328,670,491
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		29,412,802	26,785,398
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	1,107,326,144	1,055,465,461
73	Prelim. Survey and Investigation Charges (Electric) (183)		477,354	510,567
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)		26,188	-23,327
78	Miscellaneous Deferred Debits (186)	233	83,176,009	76,159,711
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)		4,554,871	5,139,793
82	Accumulated Deferred Income Taxes (190)	234	824,459,612	836,588,163
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,049,432,980	2,000,625,766
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		22,205,931,064	21,866,639,948

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

As of December 31, 2017, Account 146, Accounts receivable from associated companies, included $71,800,895 of income taxes receivable from Berkshire Hathaway Energy Company, PacifiCorp’s indirect parent company.

Schedule Page: 110 Line No.: 77 Column: d

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 2018/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	3,271,969,500	2,984,484,352
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	104,399,245	104,337,295
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)	-12,635,042	-15,266,178
16	Total Proprietary Capital (lines 2 through 15)		7,845,040,094	7,554,861,860
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	7,055,275,000	7,041,475,000
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)		36,022	47,048
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		10,793,807	10,464,531
24	Total Long-Term Debt (lines 18 through 23)		7,044,517,215	7,031,057,517
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		18,996,630	18,233,170
27	Accumulated Provision for Property Insurance (228.1)		8,591,841	6,095,041
28	Accumulated Provision for Injuries and Damages (228.2)		23,791,641	13,502,436
29	Accumulated Provision for Pensions and Benefits (228.3)		190,648,668	167,737,085
30	Accumulated Miscellaneous Operating Provisions (228.4)		34,600,459	34,624,221
31	Accumulated Provision for Rate Refunds (229)		2,551,062	5,099,189
32	Long-Term Portion of Derivative Instrument Liabilities		24,683,756	24,804,055
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		227,371,811	214,900,520
35	Total Other Noncurrent Liabilities (lines 26 through 34)		531,235,868	484,995,717
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		30,000,000	80,000,000
38	Accounts Payable (232)		523,289,313	436,508,588
39	Notes Payable to Associated Companies (233)		31,009,817	9,005,123
40	Accounts Payable to Associated Companies (234)		136,903,471	146,997,905
41	Customer Deposits (235)		49,781,902	47,576,366
42	Taxes Accrued (236)	262-263	48,581,847	46,331,988
43	Interest Accrued (237)		114,623,111	119,870,086
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)		20,623,597	19,610,180
48	Miscellaneous Current and Accrued Liabilities (242)		74,069,122	83,984,662
49	Obligations Under Capital Leases-Current (243)		1,788,634	2,004,747
50	Derivative Instrument Liabilities (244)		65,799,907	38,902,575
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		24,683,756	24,804,055
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)		1,071,827,440	1,006,028,640
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		76,528,076	36,720,467
57	Accumulated Deferred Investment Tax Credits (255)	266-267	13,313,777	15,670,323
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	202,519,682	204,360,620
60	Other Regulatory Liabilities (254)	278	2,044,239,906	2,101,876,268
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	180,339,430	185,416,334
63	Accum. Deferred Income Taxes-Other Property (282)		2,910,580,066	2,972,737,275
64	Accum. Deferred Income Taxes-Other (283)		285,789,510	272,914,927
65	Total Deferred Credits (lines 56 through 64)		5,713,310,447	5,789,696,214
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		22,205,931,064	21,866,639,948

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

Represents amounts due to Pacific Minerals, Inc., a wholly owned subsidiary of PacifiCorp, pursuant to an umbrella loan agreement for which 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, 2018, the interest rate on the outstanding loan balance was 2.85%.

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, 2017, the interest rate on the outstanding loan balance was 1.83%.

Schedule Page: 112 Line No.: 42 Column: c

As of December 31, 2018, Account 236, Taxes accrued, included $4,894,465 of income taxes payable to Berkshire Hathaway Energy Company, PacifiCorp's indirect parent company.

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 2018/Q4

STATEMENT OF INCOME

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

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	5,090,358,956	5,242,965,626		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,470,313,861	2,425,109,768		
5	Maintenance Expenses (402)	320-323	413,932,883	400,069,497		
6	Depreciation Expense (403)	336-337	908,461,901	727,650,690		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	46,883,718	41,396,782		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	5,083,195	5,083,195		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		150,275	150,507		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	201,255,354	196,653,710		
15	Income Taxes - Federal (409.1)	262-263	162,384,813	237,993,786		
16	- Other (409.1)	262-263	41,626,061	40,955,946		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	450,529,508	1,065,406,630		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	648,977,032	987,845,373		
19	Investment Tax Credit Adj. - Net (411.4)	266	-3,152,015	-3,698,228		
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)		181	178		
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)		4,048,492,341	4,148,926,732		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		1,041,866,615	1,094,038,894		

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	
						1
5,090,358,956	5,242,965,626					2
						3
2,470,313,861	2,425,109,768					4
413,932,883	400,069,497					5
908,461,901	727,650,690					6
						7
46,883,718	41,396,782					8
5,083,195	5,083,195					9
						10
						11
150,275	150,507					12
						13
201,255,354	196,653,710					14
162,384,813	237,993,786					15
41,626,061	40,955,946					16
450,529,508	1,065,406,630					17
648,977,032	987,845,373					18
-3,152,015	-3,698,228					19
						20
						21
181	178					22
						23
						24
4,048,492,341	4,148,926,732					25
1,041,866,615	1,094,038,894					26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		1,041,866,615	1,094,038,894		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		1,500,711	3,280,869		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		1,372,254	3,080,394		
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)		79,216	110,838		
35	Nonoperating Rental Income (418)		275,014	263,039		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	20,869,978	17,814,281		
37	Interest and Dividend Income (419)		14,250,874	7,989,045		
38	Allowance for Other Funds Used During Construction (419.1)		34,835,895	19,939,361		
39	Miscellaneous Nonoperating Income (421)		-728,378	2,280,438		
40	Gain on Disposition of Property (421.1)		939,906	299,714		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		70,492,530	48,675,515		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		88,035	53,895		
44	Miscellaneous Amortization (425)		1,329,336	1,328,501		
45	Donations (426.1)		2,387,899	3,297,350		
46	Life Insurance (426.2)		-3,252,632	-8,228,460		
47	Penalties (426.3)		1,112,093	-22,896		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,239,589	1,427,597		
49	Other Deductions (426.5)		7,940,472	6,007,522		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		10,844,792	3,863,509		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	340,043	314,104		
53	Income Taxes-Federal (409.2)	262-263	1,079,374	997,900		
54	Income Taxes-Other (409.2)	262-263	243,788	135,598		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	109,004,879	90,136,224		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	109,467,521	88,460,786		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		236,733	373,166		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		963,830	2,749,874		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		58,683,908	42,062,132		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		358,695,455	360,014,410		
63	Amort. of Debt Disc. and Expense (428)		4,027,405	4,121,973		
64	Amortization of Loss on Reaquired Debt (428.1)		584,922	639,595		
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)		69,069	24,990		
68	Other Interest Expense (431)		17,922,378	14,124,383		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		18,446,680	11,250,383		
70	Net Interest Charges (Total of lines 62 thru 69)		362,841,523	367,663,942		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		737,709,000	768,437,084		
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)		737,709,000	768,437,084		

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, 2018 and 2017, depreciation expense associated with transportation equipment was $15,829,896 and $15,045,329, 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, 2018 and 2017, payroll taxes were $39,770,569 and $39,077,979, 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 2018/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		2,948,638,352	2,778,346,006
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)		716,839,022	750,622,803
17	Appropriations of Retained Earnings (Acct. 436)			
18	Appropriation of excess earnings at certain hydroelectric generating facilities	215.1	-8,732,124	(10,591,983)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-8,732,124	(10,591,983)
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	-450,000,000	(600,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-450,000,000	(600,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings	216.1	20,808,028	30,423,428
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		3,227,391,376	2,948,638,352
	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 2018/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)		44,578,124	35,846,000
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		44,578,124	35,846,000
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		3,271,969,500	2,984,484,352
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		104,337,295	116,946,442
50	Equity in Earnings for Year (Credit) (Account 418.1)		20,869,978	17,814,281
51	(Less) Dividends Received (Debit)			
52	Transfers to/from Unappropriated Retained Earnings (Account 216)		-20,808,028	(30,423,428)
53	Balance-End of Year (Total lines 49 thru 52)		104,399,245	104,337,295

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

Outstanding shares of preferred stock as of December 31, 2018 and declared dividends on preferred stock during the year ended December 31, 2018 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, 2017 and declared dividends on preferred stock during the year ended December 31, 2017 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

During the year ended December 31, 2018, paid distributions from subsidiaries of PacifiCorp were as follows:

Pacific Minerals, Inc.	$18,000,000
Fossil Rock Fuels, LLC	2,663,000
Trapper Mining Inc.	145,028
	$20,808,028

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

During the year ended December 31, 2017, paid distributions from subsidiaries of PacifiCorp were as follows:

Pacific Minerals, Inc.	$27,000,000
Fossil Rock Fuels, LLC	3,394,000
Trapper Mining Inc.	29,428
	$30,423,428

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 2018/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)	737,709,000	768,437,084
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	926,028,121	748,385,225
5	Amortization:	53,322,235	47,834,694
6			
7			
8	Deferred Income Taxes (Net)	-198,910,166	79,236,695
9	Investment Tax Credit Adjustment (Net)	-3,388,748	-4,071,394
10	Net (Increase) Decrease in Receivables	22,276,393	15,260,809
11	Net (Increase) Decrease in Inventory	15,493,125	10,178,857
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	88,063,038	-34,768,339
14	Net (Increase) Decrease in Other Regulatory Assets	-19,930,064	-8,349,118
15	Net Increase (Decrease) in Other Regulatory Liabilities	107,413,446	26,841,343
16	(Less) Allowance for Other Funds Used During Construction	34,835,895	19,939,361
17	(Less) Undistributed Earnings from Subsidiary Companies	61,950	-12,609,147
18	Amounts Due To/From Affiliates (Net)	69,557,216	-51,495,765
19	Derivative Collateral (Net)	14,900,000	-5,600,000
20	Other Operating Activities:	4,701,781	7,874,142
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,782,337,532	1,592,434,019
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-1,291,567,102	-797,523,778
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	-34,835,895	-28,783,864
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,256,731,207	-768,739,914
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	4,229,118	1,680,014
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies	2,668,000	3,507,000
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 2018/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:	-2,495,368	9,546,359
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,252,329,457	-754,006,541
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	593,102,815	
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):	22,000,000	9,000,000
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	615,102,815	9,000,000
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-586,200,000	-51,722,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-1,118,205	-1,299,802
77	Repayment of Capital Lease Obligations	-1,736,324	-5,689,206
78	Net Decrease in Short-Term Debt (c)	-50,000,347	-189,924,944
79			
80	Dividends on Preferred Stock	-161,902	-161,902
81	Dividends on Common Stock	-450,000,000	-600,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-474,113,963	-839,797,854
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	55,894,112	-1,370,376
87			
88	Cash and Cash Equivalents at Beginning of Period	28,361,739	14,910,747
89			
90	Cash and Cash Equivalents at End of period	84,255,851	13,540,371

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

During the years ended December 31, 2018 and 2017, depreciation expense associated with transportation equipment and capital lease assets were $17,566,220 and $20,734,535, respectively.

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

	Years Ended December 31, 2018	Years Ended December 31, 2017
Amortization of software development & other intangibles	$ 48,213,054	$ 42,725,283
Amortization of electric plant acquisition adjustments	5,083,195	5,083,195
Amortization of a regulatory asset	25,986	26,216
	$ 53,322,235	$ 47,834,694

Schedule Page: 120 Line No.: 16 Column: c

Includes an adjustment of $8,844,503 to Account 419.1, Allowance for other funds used during construction, per FERC Docket No. FA16-4-000.

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

	Years Ended December 31, 2018	Years Ended December 31, 2017
Depreciation and depletion included in cost of fuel	$ 2,076,162	$ 2,039,189
Net gain on sale of property	(955,310)	(282,093)
Write-off of assets under construction	1,903,891	8,006,117
Change in corporate owned life insurance cash surrender value	(3,241,715)	(8,195,039)
Amortization of debt issuance expenses and bond discount/premium	4,016,379	4,110,947
Changes in derivative contract assets/liabilities, net	(941,213)	(881,283)
Noncash adjustment to allowance for borrowed funds used during construction, per FERC Docket No. FA16-4-000	-	4,429,935
Other	1,843,587	(1,353,631)
	$ 4,701,781	$ 7,874,142

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, 2018	Years Ended December 31, 2017
Other investments/special funds	$ 1,986,133	$ 714,850
Restricted cash	-	1,138,310
Investment in long-term incentive plan securities	(4,481,501)	(2,174,547)
Investment in supplemental executive retirement plan	-	9,867,746
	$ (2,495,368)	$ 9,546,359

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

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

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

Other deferred financing costs

Schedule Page: 120 Line No.: 88 Column: b

Cash and cash equivalents and restricted cash and cash equivalents consist of the following amounts as of December 31, 2017:

Cash (131)	$ 4,805,006
Temporary cash investments (136)	8,735,365
Total cash and cash equivalents	13,540,371
Other special funds (128)	5,930,367
Other special deposits (134)	8,891,001
Total restricted cash and cash equivalents	14,821,368
Total cash and cash equivalents and restricted cash and cash equivalents	$ 28,361,739

NOTES TO FINANCIAL STATEMENTS

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

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

PACIFICORP
NOTES TO FINANCIAL STATEMENTS

(1) Organization and Operations

PacifiCorp is a United States regulated electric utility company serving retail customers, including residential, commercial, industrial, irrigation and other customers in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp owns, or has interests in, a number of thermal, hydroelectric, wind-powered and geothermal generating facilities, as well as electric transmission and distribution assets. PacifiCorp also buys and sells electricity on the wholesale market with other utilities, energy marketing companies, financial institutions and other market participants. PacifiCorp is subject to comprehensive state and federal regulation. PacifiCorp 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. AC11-132-000, 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. AC11-132-000, 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.

Pensions and Postretirement Benefits Other Than Pensions

Pension and postretirement benefits other than pensions ("PBOP") are comprised of several different components of net periodic benefit costs. As required by GAAP, the service cost component is reported with other compensation costs arising from services rendered by employees, while the other components of net periodic benefit costs are presented outside of operating income. Additionally, only the service cost component of net periodic benefit costs is eligible for capitalization under GAAP. In accordance with FERC Order No. AI18-1-000, PacifiCorp continues to report the components of net periodic benefit costs for pension and PBOP on the statement of income and follows GAAP guidance to capitalize only the service cost component of net periodic benefit costs.

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 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 Cash Equivalents 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 cash and cash equivalents are included in other special funds and other special deposits primarily consist of escrow accounts for disputed funds, vendor retention, custodial and nuclear decommissioning funds.

Cash and cash equivalents and restricted cash and cash equivalents consist of the following amounts as of December 31 (in millions):

	2018	2017
Cash (131)	$ 20	$ 5
Temporary cash investments (136)	49	9
Total cash and cash equivalents	69	14
Other special funds (128)	15	5
Other special deposits (134)	—	9
Total restricted cash and cash equivalents	15	14
Total cash and cash equivalents and restricted cash and cash equivalents	$ 84	$ 28

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, 2018 and 2017, 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 collectability 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):

	2018	2017
Beginning balance	$ 10	$ 7
Charged to operating costs and expenses, net	12	15
Write-offs, net	(14)	(12)
Ending balance	$ 8	$ 10

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 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 operating expenses on the Statement of Income.

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

Inventories

Inventories consist mainly of materials and supplies and fuel stocks (coal, 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 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, net) 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, appropriate FERC accounts are adjusted to write down the asset 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

PacifiCorp recognizes revenues from contracts with customers ("Customer Revenue") upon transfer of control of promised goods or services in an amount that reflects the consideration to which PacifiCorp expects to be entitled in exchange for those goods or services. 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.

Substantially all of PacifiCorp's Customer Revenue is derived from tariff-based sales arrangements approved by various regulatory authorities. These tariff-based revenues are mainly comprised of energy, transmission and distribution and have performance obligations to deliver energy products and services to customers which are satisfied over time as energy is delivered or services are provided. Other revenue consists of contractual agreements, including derivative arrangements.

Revenue recognized is 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 and includes billed and unbilled amounts. Payments for amounts billed are generally due from the customer within 30 days of billing. Rates charged for energy products and services are established by regulators or contractual arrangements that establish the transaction price as well as the allocation of price amongst the separate performance obligations. When preliminary regulated rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and classified in accordance with FERC accounting standards.

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 certain property-related basis differences and other various differences that PacifiCorp deems probable to be passed on to its customers in most state jurisdictions are charged or credited directly to a regulatory asset or liability and will be included in regulated rates when the temporary differences reverse or as otherwise approved by PacifiCorp's various regulatory commissions. 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 commissions. 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 August 2018, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2018-14, which amends FASB Accounting Standards Codification ("ASC") Topic 715, "Compensation - Retirement Benefits." The amendments in this guidance modify the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. The amendments in this guidance remove disclosures that no longer are considered cost beneficial, clarify the specific requirements of disclosures and add disclosure requirements identified as relevant. The updated disclosure requirements make a number of changes to improve the effectiveness of disclosures within the notes to financial statements. This guidance is effective for annual reporting periods ending after December 15, 2020, with early adoption permitted and is required to be adopted retrospectively. PacifiCorp elected to early adopt ASU No. 2018-14 effective December 31, 2018. The adoption did not have a material impact on PacifiCorp's financial statements and disclosures included within Notes to Financial Statements.

In March 2017, the FASB issued ASU No. 2017-07, which amends FASB ASC Topic 715, "Compensation - Retirement Benefits." The amendments in this guidance require that an employer disaggregate the service cost component from the other components of net benefit cost and report the service cost component in the same GAAP financial statement line item 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 GAAP statement of operations separately from the service cost component and outside the subtotal of operating income. Additionally, the guidance only allows the service cost component to be eligible for capitalization when applicable. PacifiCorp adopted this guidance January 1, 2018 prospectively for the capitalization of the service cost component and is in accordance with requirements specified in FERC Order No. AI18-1-000, "Accounting and Financial Reporting for Pensions and Post-retirement Benefits other than Pensions".

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 and 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. PacifiCorp adopted this guidance January 1, 2018 for FERC reporting, as presented in the Statement of Cash Flows.

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. PacifiCorp adopted this guidance January 1, 2018 for FERC reporting.

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 on 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. During 2018, the FASB issued several ASUs that clarified the implementation guidance and provided optional transition practical expedients for ASU No. 2016-02 including ASU No. 2018-01 that allows companies to forgo evaluating existing land easements if they were not previously accounted for under ASC Topic 840, "Leases" and ASU No. 2018-11 that allows companies to apply the new guidance at the adoption date with the cumulative-effect adjustment to the opening balance of retained earnings recognized in the period of adoption. 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 adopted this guidance, electing all practical expedients, effective January 1, 2019, for all contracts currently in-effect. PacifiCorp is finalizing its implementation efforts relative to the new guidance and currently expects to recognize operating lease right of use assets and lease liabilities of approximately $15 million based on the contracts currently in-effect. PacifiCorp's implementation of this guidance will be in accordance with FERC Order No. AI19-1-000, "Accounting and Financial Reporting for Leases" issued December 27, 2018.

In May 2014, the FASB issued ASU No. 2014-09, which created FASB ASC Topic 606, "Revenue from Contracts with Customers" ("ASC 606") and superseded ASC Topic 605, "Revenue Recognition." The guidance replaced industry-specific guidance and established a single five-step model to identify and recognize revenue Customer Revenue. The core principle of the GAAP 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. Following the issuance of ASU No. 2014-09, the FASB issued several ASUs that clarified the implementation guidance for ASU No. 2014-09 but did not change the core principle of the guidance. PacifiCorp adopted this guidance for all applicable contracts as of January 1, 2018 under a modified retrospective method. The adoption did not have a cumulative effect impact at the date of initial adoption.

Subsequent Events

PacifiCorp has evaluated the impact of events occurring after December 31, 2018 up to February 22, 2019, the date that PacifiCorp's GAAP financial statements were filed with the United States Securities and Exchange Commission and has updated such evaluation for disclosure purposes through April 12, 2019. 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 3.5% for the year ended December 31, 2018, including the impact of accelerated depreciation for Utah's share of certain thermal plant units, and 2.9% for the year ended December 31, 2017.

(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, 2018 (dollars in millions):

	PacifiCorp Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Jim Bridger Nos. 1 - 4[1]	67 %	$ 1,458	$ 659	$ 11
Hunter No. 1	94	484	176	—
Hunter No. 2	60	298	116	5
Wyodak	80	471	226	—
Colstrip Nos. 3 and 4	10	248	136	6
Hermiston	50	180	87	1
Craig Nos. 1 and 2	19	367	245	—
Hayden No. 1	25	74	38	—
Hayden No. 2	13	43	22	—
Foote Creek	79	40	27	1
Transmission and distribution facilities	Various	808	296	76
Total		$ 4,471	$ 2,028	$ 100

(1) Includes PacifiCorp's share of disallowances resulting from a rate settlement with the Washington Utilities and Transportation Commission ("WUTC").

(5) Regulatory Matters

Regulatory Assets

PacifiCorp had regulatory assets not earning a return on investment of $631 million and $584 million as of December 31, 2018 and 2017, respectively.

(6) Short-term Debt and Credit Facilities

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

2018:	
Credit facilities	$ 1,200
Less:	
Short-term debt	(30)
Tax-exempt bond support	(89)
Net credit facilities	$ 1,081
2017:	
Credit facilities	$ 1,000
Less:	
Short-term debt	(80)
Tax-exempt bond support	(130)
Net credit facilities	$ 790

PacifiCorp has a $600 million unsecured credit facility expiring in June 2021 with a one-year extension option subject to lender consent and a $600 million unsecured credit facility expiring in June 2021 with two one-year extension options subject to lender 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 variable interest rates based on the Eurodollar 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, 2018 and 2017, the weighted average interest rate on commercial paper borrowings outstanding was 2.85% and 1.83%, 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, 2018 and 2017, PacifiCorp had $184 million and $230 million, respectively, of fully available letters of credit issued under committed arrangements. As of December 31, 2018 and 2017, $170 million and $216 million, respectively, of these letters of credit, support PacifiCorp's variable-rate tax-exempt bond obligations and expire in March 2019 and $14 million support certain transactions required by third parties 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.

In March 2019, PacifiCorp completed a re-offering of variable rate tax-exempt bond obligations totaling $168 million, involving the cancellation at PacifiCorp's request for $170 million of letters of credit support by the issuing banks. As a result, PacifiCorp's credit facility support for outstanding variable rate tax-exempt bond obligations increased by $168 million.

(7) Long-term Debt and Capital Lease Obligations

As of April 2019, PacifiCorp currently has regulatory authority from the Oregon Public Utility Commission ("OPUC") and the Idaho Public Utilities Commission ("IPUC") to issue an additional $1.0 billion of long-term debt. PacifiCorp must make a notice filing with the WUTC prior to any future issuance. As of April 2019, PacifiCorp currently has an effective shelf registration statement filed with the United States Securities and Exchange Commission to issue up to $1.0 billion additional first mortgage bonds through October 2021.

In March 2019, PacifiCorp issued $400 million of its 3.500% First Mortgage Bonds due June 2029 and $600 million of its 4.150% First Mortgage Bonds due February 2050. PacifiCorp used a portion of the net proceeds to repay short-term debt that was partially incurred to repay all of PacifiCorp's $350 million of its 5.50% First Mortgage Bonds due January 2019. PacifiCorp intends to use the remaining net proceeds to fund capital expenditures and for general corporate purposes.

In July 2018, PacifiCorp issued $600 million of its 4.125% First Mortgage Bonds due January 2049. PacifiCorp used a portion of the net proceeds to repay all of PacifiCorp's $500 million 5.65% First Mortgage Bonds due July 2018 and used the remaining net proceeds to fund capital expenditures and for general corporate purposes.

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.

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately $28 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2018.

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 $21 million and $20 million as of December 31, 2018 and 2017, respectively, were included in net utility plant on the Comparative Balance Sheet.

As of December 31, 2018, the annual principal maturities of long-term debt and total capital lease obligations excluding unamortized discount for 2019 and thereafter are as follows (in millions):

	Long-term Debt	Capital Lease Obligations	Total
2019	$ 350	$ 4	$ 354
2020	38	3	41
2021	420	7	427
2022	605	3	608
2023	449	2	451
Thereafter	5,193	16	5,209
Total	7,055	35	7,090
Unamortized discount	(10)	—	(10)
Amounts representing interest	—	(14)	(14)
Total	$ 7,045	$ 21	$ 7,066

(8) Income Taxes

Tax Cuts and Jobs Act

The Tax Cuts and Jobs Act enacted on December 22, 2017 ("2017 Tax Reform") impacted many areas of income tax law. The most material items included the reduction of the federal corporate tax rate from 35% to 21% effective January 1, 2018 and limitations on bonus depreciation for utility property.

In December 2017, the SEC issued Staff Accounting Bulletin 118 to assist in the implementation process of the 2017 Tax Reform by allowing for calculations to be classified as provisional and subject to remeasurement. There are three different classifications for the accounting: (1) completed, (2) not complete but reasonably estimable or (3) not complete and amounts are not reasonably estimable. On December 31, 2017, PacifiCorp recorded the impacts of the 2017 Tax Reform and believed all the impacts to be complete with the exception of interpretations of the bonus depreciation rules. PacifiCorp determined the amounts recorded and the interpretations relating to this item to be provisional and subject to remeasurement during the measurement period upon obtaining the necessary additional information to complete the accounting. PacifiCorp believed its interpretations for bonus depreciation to be reasonable, however, clarifying guidance was needed. During 2018, PacifiCorp finalized its provisional amounts recording a current tax benefit and deferred tax expense of $21 million following clarifying bonus depreciation guidance. As a result of 2017 Tax Reform and PacifiCorp's regulatory nature, PacifiCorp reduced the associated deferred income tax liabilities $8 million and increased regulatory liabilities by the same amount.

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

	2018	2017
Current:		
Federal	$ 163	$ 239
State	42	41
Total	205	280
Deferred:		
Federal	(190)	63
State	(9)	16
Total	(199)	79
Investment tax credits	(3)	(4)
Total income tax expense	$ 3	$ 355

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:

	2018	2017
Federal statutory income tax rate	21%	35%
State income taxes, net of federal income tax benefit	4	3
Amortization of excess deferred income taxes	(17)	—
Federal income tax credits	(7)	(5)
Other	(1)	(1)
Effective income tax rate	—%	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. Amortization of excess deferred income taxes is primarily attributable to the amortization of $127 million of Utah allocated excess deferred income taxes pursuant to a 2017 Tax Reform settlement approved by the Utah Public Service Commission ("UPSC"), whereby a portion of Utah allocated excess deferred income taxes was used to accelerate depreciation on Utah's share of certain thermal plant units.

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

	2018	2017
Deferred income tax assets:		
Regulatory liabilities	$ 503	$ 517
Employee benefits	91	84
Derivative contracts and unamortized contract values	45	48
State carryforwards	77	83
Asset retirement obligations	53	50
Other	55	54
	824	836
Deferred income tax liabilities:		
Property, plant and equipment	(3,091)	(3,157)
Regulatory assets	(273)	(261)
Other	(12)	(12)
	(3,376)	(3,430)
Net deferred income tax liability	$ (2,552)	$ (2,594)

The following table provides PacifiCorp's net operating loss and tax credit carryforwards and expiration dates as of December 31, 2018 (in millions):

	State
Net operating loss carryforwards	$ 1,230
Deferred income taxes on net operating loss carryforwards	$ 58
Expiration dates	2019 - 2032
Tax credit carryforwards	$ 19
Expiration dates	2019 - indefinite

The United States Internal Revenue Service has closed its examination of PacifiCorp's income tax returns through December 31, 2011. The statute of limitations for PacifiCorp's state income tax returns have expired through December 31, 2009, with the exception of Idaho, for which the statute of limitations has expired through December 31, 2014, except for the impact of any federal audit adjustments. The statute of limitations expiring for state filings may not preclude the state from adjusting the state net operating loss carryforward utilized in a year for which the statute of limitations is not closed.

In general, PacifiCorp's excess deferred income tax was calculated by measuring the difference between the gross temporary differences as of December 31, 2017 at PacifiCorp's post-tax reform combined federal and state statutory income tax rate, as compared to the same gross temporary differences at PacifiCorp's pre-tax reform combined federal and state statutory income tax rate. As of December 31, 2017, an estimate of excess deferred income tax was recorded in Account 254, Regulatory liabilities. The excess deferred income tax balances presented in the table below represents the final excess deferred income tax balances after the completion of PacifiCorp's December 31, 2017 federal income tax return and does not reflect any amortizations recorded during the year ended December 31, 2018 (in millions):

	Protected(1)	Non-Protected(2)	Total
Deferred income tax asset (190)	$ —	$ 63	$ 63
Deferred income tax liability			
Accelerated amortization property (281)	(94)	(5)	(99)
Other property (282)	(1,218)	(372)	(1,590)
Other (283)	—	(200)	(200)
	(1,312)	(577)	(1,889)
Other regulatory assets (182.3)	—	190	190
Total excess deferred income taxes	$ (1,312)	$ (324)	$ (1,636)
Gross-up			(533)
Regulatory Liabilities (254)			$ (2,169)

(1) Protected excess deferred tax balances will be amortized using the Average Rate Assumption Method over the remaining book life of the related assets to Account 411.1, Provision for deferred income taxes-credit.

(2) Non-protected excess deferred income tax balances will amortize over the period authorized by each of PacifiCorp's regulatory commissions and amortized to Account 411.1, Provision for deferred income taxes-credit. The UPSC authorized the full amortization of non-protected balances in 2018 and in Idaho, a stipulation was filed and expected to be amortized over seven-years. For all other jurisdictions, the amortization period has not yet been determined.

The company is working to include a mechanism for excess deferred income tax in its FERC formula rate. The status of tax reform is further discussed below by state jurisdiction.

Utah

In April 2018, the UPSC ordered a rate reduction of $61 million, or 4.7%, effective May 1, 2018 through December 31, 2018, based on a preliminary estimate of the revenue requirement impact of 2017 Tax Reform. In November 2018, the UPSC approved an all-party settlement that continues the current rate reduction of $61 million, with other benefits provided to customers through a combination of $174 million of accelerated depreciation of certain thermal steam plant units and deferral of other benefits to offset costs in the next general rate case.

Oregon

In December 2018, PacifiCorp proposed to reduce customer rates to reflect the lower annual current income tax expense in Oregon resulting from 2017 Tax Reform. PacifiCorp reached an all-party settlement on the amortization of the current income tax expense benefits and the deferral of the decision regarding the ratemaking treatment of excess deferred income tax balances until PacifiCorp's next rate case. The settlement, which results in a rate reduction of $48 million, or 3.7%, effective February 1, 2019, was approved by the OPUC in January 2019.

Wyoming

In April 2018, PacifiCorp filed a partial settlement related to the impact of 2017 Tax Reform with the Wyoming Public Service Commission ("WPSC") that provides a rate reduction of $23 million, or 3.3%, effective July 1, 2018 through June 30, 2019, with the remaining tax savings to be deferred with offsets to other costs. In June 2018, the WPSC approved the rate reduction on an interim basis. In June 2018, PacifiCorp filed reports with the WPSC with the calculation of the full impact of the tax law change on revenue requirement of $28 million annually, comprised of $20 million in current tax savings and $8 million for the amortization of excess deferred income tax. These reports initiated the next phase of the proceedings including a hearing held in January 2019 and public deliberations in February 2019. During public deliberations the WPSC approved the continuation of the rate reduction until the next general rate case with other savings to be deferred to offset other costs. In March 2019, the WPSC issued a written order approving the continued annual rate reduction of $23 million until base rates are reset in the next general rate proceeding with an additional $4 million to be offset against PacifiCorp’s 2018 energy cost adjustment mechanism. The order reflected the $20 million of current tax savings and was updated to reflect a projection of $7 million for amortization of excess deferred income tax.

Washington

In November 2018, PacifiCorp proposed to reduce customer rates by $8 million, or 2.3%, effective January 1, 2019, to reflect the lower annual current income tax expense in Washington resulting from 2017 Tax Reform and to defer all other tax savings to offset costs in the next general rate case. PacifiCorp's proposal was approved by the WUTC in December 2018.

Idaho

In May 2018, the IPUC approved an all-party settlement to implement a rate reduction of $6 million, or 2.2%, effective June 1, 2018 through May 31, 2019, to pass back a portion of the benefits associated with 2017 Tax Reform. The credit may be adjusted following the next phase of the proceeding. In June 2018, PacifiCorp filed a report with the IPUC with the calculation of the full impact of the tax law change on revenue requirement of $11 million annually, comprised of $8 million in current tax savings and $3 million of the amortization of excess deferred income tax. In March 2019, a stipulation was filed to resolve the treatment of the remaining tax savings, including an additional $7 million to be returned to customers or used to offset customer costs effective June 1, 2019.

California

The decision on how to return the benefits associated with 2017 Tax Reform to California customers has not been finalized.

(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.

<u>Defined Benefit Plans</u>

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.

During 2018, the Retirement Plan incurred a settlement charge of $22 million as a result of excess lump sum distributions over the defined threshold for the year ended December 31, 2018.

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

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

	Pension		Other Postretirement	
	2018	**2017**	**2018**	**2017**
Service cost	$ —	$ —	$ 2	$ 2
Interest cost	43	49	11	14
Expected return on plan assets	(72)	(72)	(21)	(21)
Settlement	22	—	—	—
Net amortization	13	14	(6)	(6)
Net period benefit cost (credit)	$ 6	$ (9)	$ (14)	$ (11)

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	
	2018	**2017**	**2018**	**2017**
Plan assets at fair value, beginning of year	$ 1,111	$ 999	$ 332	$ 302
Employer contributions	4	54	1	1
Participant contributions	—	—	5	7
Actual return on plan assets	(52)	166	(16)	49
Settlement	(52)	—	—	—
Benefits paid	(69)	(108)	(25)	(27)
Plan assets at fair value, end of year	$ 942	$ 1,111	$ 297	$ 332

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

	Pension		Other Postretirement	
	2018	**2017**	**2018**	**2017**
Benefit obligation, beginning of year	$ 1,251	$ 1,276	$ 331	$ 358
Service cost	—	—	2	2
Interest cost	43	49	11	14
Participant contributions	—	—	5	7
Actuarial (gain) loss	(68)	34	(26)	(23)
Settlement	(52)	—	—	—
Benefits paid	(69)	(108)	(25)	(27)
Benefit obligation, end of year	$ 1,105	$ 1,251	$ 298	$ 331
Accumulated benefit obligation, end of year	$ 1,105	$ 1,251		

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	
	2018	2017	2018	2017
Plan assets at fair value, end of year	$ 942	$ 1,111	$ 297	$ 332
Less - Benefit obligation, end of year	1,105	1,251	298	331
Funded status	$ (163)	$ (140)	$ (1)	$ 1
Amounts recognized on the Comparative Balance Sheet:				
Other special funds (128)	$ —	$ —	$ —	$ 1
Miscellaneous current and accrued liabilities (242)	(4)	(4)	—	—
Accumulated provision for pension and benefits (228.3)	(159)	(136)	(1)	—
Amounts recognized	$ (163)	$ (140)	$ (1)	$ 1

The SERP has no plan assets; however, PacifiCorp has a Rabbi trust that holds corporate-owned life insurance and other investments to provide funding for the future cash requirements of the SERP. The cash surrender value of all of the policies included in the Rabbi trust, net of amounts borrowed against the cash surrender value, plus the fair market value of other Rabbi trust investments, was $52 million and $60 million as of December 31, 2018 and 2017, respectively. These assets are not included in the plan assets in the above table, but are reflected in temporary cash investments, totaling $1 million and $9 million as of December 31, 2018 and 2017, respectively, and other investments, totaling $51 million as of December 31, 2018 and 2017 on the Comparative Balance Sheet.

The projected benefit obligation for the pension and other postretirement plans were in excess of the fair value of their respective plans assets as of December 31, 2018. The accumulated benefit obligation for the pension plans was in excess of the fair value of plan assets as of December 31, 2018.

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	
	2018	2017	2018	2017
Net loss (gain)	$ 461	$ 442	$ (2)	$ (12)
Prior service credit	—	—	—	(6)
Regulatory deferrals	(1)	(4)	7	7
Total	$ 460	$ 438	$ 5	$ (11)

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2018 and 2017 is as follows (in millions):

	Regulatory Asset	Accumulated Other Comprehensive Loss	Total
Pension			
Balance, December 31, 2016	$ 491	$ 20	$ 511
Net (gain) loss arising during the year	(60)	1	(59)
Net amortization	(13)	(1)	(14)
Total	(73)	—	(73)
Balance, December 31, 2017	418	20	438
Net loss (gain) arising during the year	59	(2)	57
Net amortization	(12)	(1)	(13)
Settlement	(22)	—	(22)
Total	25	(3)	22
Balance, December 31, 2018	$ 443	$ 17	$ 460

	Regulatory Asset (Liability)
Other Postretirement	
Balance, December 31, 2016	$ 34
Net gain arising during the year	(51)
Net amortization	6
Total	(45)
Balance, December 31, 2017	(11)
Net loss arising during the year	10
Net amortization	6
Total	16
Balance, December 31, 2018	$ 5

Plan Assumptions

	Pension		Other Postretirement	
	2018	2017	2018	2017
Benefit obligations as of December 31:				
Discount rate	4.25%	3.60%	4.25%	3.60%
Rate of compensation increase	N/A	N/A	N/A	N/A
Interest crediting rates for cash balance plan(1)(2)	3.40%	1.61%	N/A	N/A
Net periodic benefit cost for the years ended December 31:				
Discount rate	3.60%	4.05%	3.60%	4.05%
Expected return on plan assets	7.00	7.25	6.86	7.25
Rate of compensation increase	N/A	N/A	N/A	N/A

(1) 2018 Cash Balance Interest Crediting Rate assumption is 3.40% for 2019 and all future years for nonunion participants and 3.15% for 2019-2020 and 3.25% for 2021+ for union participants.

(2) 2017 Cash Balance Interest Crediting Rate assumption was 2.26% for 2018-2019 and 1.60% for 2020+ for nonunion participants and 2.78% for 2018-2019 and 2.60% for 2020+ for union participants.

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 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 a labor settlement reached with United Mine Workers of America ("UMWA") in December 2014, 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 $4 million and $- million, respectively, during 2019. 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 of its other postretirement benefit plan is subject to tax deductibility and subordination limits and other considerations.

The expected benefit payments to participants in PacifiCorp's pension and other postretirement benefit plans for 2019 through 2023 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	**Other Postretirement**
2019	$ 105	$ 24
2020	102	26
2021	98	23
2022	92	22
2023	88	21
2024-2028	369	95

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, 2018:

	Pension(1)	**Other Postretirement**(1)
	%	%
Debt securities(2)	30 - 43	33 - 37
Equity securities(2)	48 - 65	62 - 66
Limited partnership interests	6 - 12	1 - 3

(1) PacifiCorp's Retirement Plan trust includes a separate account that is used to fund benefits for the other postretirement benefit plan. In addition to this separate account, the assets for the other postretirement benefit plan are held in Voluntary Employees' Beneficiary Association ("VEBA") trusts, each of which has its own investment allocation strategies. Target allocations for the other postretirement benefit plan include the separate account of the Retirement Plan trust and the VEBA trusts.

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

Fair Value Measurements

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

	Input Levels for Fair Value Measurements			
	Level 1(1)	Level 2(1)	Level 3(1)	Total
As of December 31, 2018:				
Cash and cash equivalents	$ —	$ 11	$ —	$ 11
Debt securities:				
United States government obligations	4	—	—	4
International government obligations	—	1		1
Corporate obligations	—	88	—	88
Municipal obligations	—	10	—	10
Agency, asset and mortgage-backed obligations	—	43	—	43
Equity securities:				
United States companies	327	—	—	327
International companies	15	—	—	15
Investment funds(2)	54	—	—	54
Total assets in the fair value hierarchy	$ 400	$ 153	$ —	553
Investment funds(2) measured at net asset value				285
Limited partnership interests(3) measured at net asset value				104
Investments at fair value				$ 942
As of December 31, 2017:				
Cash and cash equivalents	$ —	$ 43	$ —	$ 43
Debt securities:				
United States government obligations	45	—	—	45
Corporate obligations	—	60	—	60
Municipal obligations	—	9	—	9
Agency, asset and mortgage-backed obligations	—	37	—	37
Equity securities:				
United States companies	416	—	—	416
International companies	22	—	—	22
Total assets in the fair value hierarchy	$ 483	$ 149	$ —	632
Investment funds(2) measured at net asset value				416
Limited partnership interests(3) measured at net asset value				63
Investments at fair value				$ 1,111

(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 55% and 45% respectively, for 2018 and 60% and 40%, respectively, for 2017, and are invested in United States and international securities of approximately 68% and 32%, respectively, for 2018 and 57% and 43%, respectively, for 2017.

(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, 2018:				
Cash and cash equivalents	$ 4	$ 1	$ —	$ 5
Debt securities:				
United States government obligations	3	—	—	3
Corporate obligations	—	23	—	23
Municipal obligations	—	2	—	2
Agency, asset and mortgage-backed obligations	—	17	—	17
Equity securities:				
United States companies	83	—	—	83
International companies	4	—	—	4
Investment funds(2)	38	—	—	38
Total assets in the fair value hierarchy	$ 132	$ 43	$ —	175
Investment funds(2) measured at net asset value				116
Limited partnership interests(3) measured at net asset value				6
Investments at fair value				$ 297
As of December 31, 2017:				
Cash and cash equivalents	$ 4	$ 3	$ —	$ 7
Debt securities:				
United States government obligations	11	—	—	11
Corporate obligations	—	16	—	16
Municipal obligations	—	2	—	2
Agency, asset and mortgage-backed obligations	—	16	—	16
Equity securities:				
United States companies	98	—	—	98
International companies	6	—	—	6
Investment funds(2)	32	—	—	32
Total assets in the fair value hierarchy	$ 151	$ 37	$ —	188
Investment funds(2) measured at net asset value				140
Limited partnership interests(3) measured at net asset value				4
Investments at fair value				$ 332

(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 59% and 41%, respectively, for 2018 and 63% and 37%, respectively, for 2017, and are invested in United States and international securities of approximately 90% and 10%, respectively, for 2018 and 77% and 23%, respectively, for 2017.

(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 wholly owned 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 wholly owned 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 participation in individually significant joint trustee and multiemployer pension plans for the years ended December 31 (dollars in millions):

		PPA zone status or plan funded status percentage for plan years beginning July 1,				Contributions(1)		
Plan name	**Employer Identification Number**	**2018**	**2017**	**Funding improvement plan**	**Surcharge imposed under PPA(1)**	**2018**	**2017**	**Year contributions to plan exceeded more than 5% of total contributions(2)**
Local 57 Trust Fund	87-0640888	At least 80%	At least 80%	None	None	$ 7	$ 7	2016, 2015

(1) PacifiCorp's minimum contributions to the plan are based on the amount of wages paid to employees covered by the Local 57 Trust Fund collective bargaining agreements, subject to ERISA minimum funding requirements.

(2) For the Local 57 Trust Fund, information is for plan years beginning July 1, 2016 and 2015. Information for the plan year beginning July 1, 2017 is not yet available.

The current collective bargaining agreements governing the Local 57 Trust Fund expires in 2023.

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, 2018, 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 $39 million for the years ended December 31, 2018 and 2017.

(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 $994 million and $955 million as of December 31, 2018 and 2017, respectively.

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

	2018	2017
Beginning balance	$ 215	$ 215
Change in estimated costs	9	(8)
Additions	—	6
Retirements	(5)	(6)
Accretion	8	8
Ending balance	$ 227	$ 215

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.

(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, 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, 2018:					
Not designated as hedging contracts[1]:					
Commodity assets	$ 36	$ 4	$ 10	$ 1	$ 51
Commodity liabilities	(9)	(1)	(67)	(71)	(148)
Total	27	3	(57)	(70)	(97)
Total derivatives	27	3	(57)	(70)	(97)
Cash collateral receivable	(2)	—	16	45	59
Total derivatives - net basis	$ 25	$ 3	$ (41)	$ (25)	$ (38)
As of December 31, 2017:					
Not designated as hedging contracts[1]:					
Commodity assets	$ 11	$ 1	$ 1	$ —	$ 13
Commodity liabilities	(3)	—	(32)	(82)	(117)
Total	8	1	(31)	(82)	(104)
Total derivatives	8	1	(31)	(82)	(104)
Cash collateral receivable	—	—	17	57	74
Total derivatives - net basis	$ 8	$ 1	$ (14)	$ (25)	$ (30)

(1) PacifiCorp's commodity derivatives are generally included in rates and as of December 31, 2018 and 2017, a regulatory asset of $96 million and $101 million, respectively, was recorded related to the net derivative liability of $97 million and $104 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):

	2018	2017
Beginning balance	$ 101	$ 73
Changes in fair value recognized in regulatory assets	12	47
Net (losses) gains reclassified to operating revenue	(68)	9
Net gains (losses) reclassified to energy costs	51	(28)
Ending balance	$ 96	$ 101

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	2018	2017
Electricity sales	Megawatt hours	(6)	(9)
Natural gas purchases	Decatherms	117	113
Fuel oil purchases	Gallons	—	—

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, 2018, PacifiCorp's credit ratings for its senior secured debt and its issuer credit ratings for senior unsecured debt by Moody's Investor Service and Standard & Poor's Rating Services were investment grade.

The aggregate fair value of PacifiCorp's derivative contracts in liability positions with specific credit-risk-related contingent features totaled $113 million and $110 million as of December 31, 2018 and 2017, respectively, for which PacifiCorp had posted collateral of $61 million and $74 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, 2018 and 2017, PacifiCorp would have been required to post $35 million and $34 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, 2018 and December 31, 2017, PacifiCorp would have been required to post $289 million and $233 million, respectively, of additional collateral.

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

(12) Fair Value Measurements

The carrying value of PacifiCorp's cash, certain cash equivalents, receivables, other special funds, other investments, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. PacifiCorp has various financial assets and liabilities that are measured at fair value on the financial statements using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

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

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

	Input Levels for Fair Value Measurements				
	Level 1	**Level 2**	**Level 3**	**Other(1)**	**Total**
As of December 31, 2018:					
Assets:					
Commodity derivatives	$ —	$ 51	$ —	$ (23)	$ 28
Money market mutual funds(2)	63	—	—	—	63
Investment funds	24	—	—	—	24
	$ 87	$ 51	$ —	$ (23)	$ 115
Liabilities - Commodity derivatives	$ —	$ (148)	$ —	$ 82	$ (66)
As of December 31, 2017:					
Assets:					
Commodity derivatives	$ —	$ 13	$ —	$ (4)	$ 9
Money market mutual funds(2)	21	—	—	—	21
Investment funds	21	—	—	—	21
	$ 42	$ 13	$ —	$ (4)	$ 51
Liabilities - Commodity derivatives	$ —	$ (117)	$ —	$ 78	$ (39)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $59 million and $74 million as of December 31, 2018 and 2017, respectively.

(2) Amounts are included in other special funds and 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 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 three 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 three 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 financial statements. 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):

	2018		2017	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 7,045	$ 7,833	$ 7,031	$ 8,370

(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 is determined dam removal should proceed, dam removal would begin no earlier than 2020.

Congress failed to pass legislation needed to implement the original KHSA. In April 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 amendment to the KHSA. Consistent with the terms of the amended KHSA, in September 2016, PacifiCorp and the Klamath River Renewal Corporation ("KRRC"), a private, independent nonprofit 501(c)(3) organization formed by certain signatories of the amended KSHA, 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 in September 2016, the KRRC filed an application with the FERC to surrender the license and decommission the same four 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. In March 2018, the FERC issued an order splitting the existing license for the Klamath Project into two licenses: the Klamath Project (P-2082) contains East Side, West Side, Keno and Fall Creek developments; the new Lower Klamath Project (P-14803) contains J.C. Boyle, Copco No. 1, Copco No. 2 and Iron Gate developments. In the same order, the FERC deferred consideration of the transfer of the license for the Lower Klamath facilities from PacifiCorp to the KRRC until some point in the future. PacifiCorp is currently the licensee for both the Klamath Project and Lower Klamath Project facilities and will retain ownership of the Klamath Project facilities after the approval and transfer of the Lower Klamath Project facilities. In April 2018, PacifiCorp filed a motion to stay the effective date of the license amendment until transfer is approved. In June 2018, the FERC granted PacifiCorp's motion to stay the effective date of the Lower Klamath Project license and all related compliance obligations, pending a FERC order on the license transfer. Meanwhile, the FERC continues to assess the KRRC's capacity to become a project licensee for purposes of dam removal. The United States Court of Appeals for the District of Columbia Circuit issued a decision in the *Hoopa Valley Tribe v. FERC* litigation, on January 25, 2019, finding that the states of California and Oregon have waived their Clean Water Act, Section 401, water quality certification authority over the Klamath hydroelectric project relicensing. PacifiCorp is evaluating the impact of this decision.

Under the amended KHSA, PacifiCorp and its customers are 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 toward facilities removal costs are being 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 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, 2018, PacifiCorp's assets included $44 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 $155 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, 2018 are as follows (in millions):

	2019	2020	2021	2022	2023	2024 and Thereafter	Total
Contract type:							
Purchased electricity contracts - commercially operable	$ 317	$ 194	$ 155	$ 152	$ 145	$ 1,522	$ 2,485
Purchased electricity contracts - non-commercially operable	13	21	48	49	49	797	977
Fuel contracts	732	648	521	326	268	976	3,471
Construction commitments	888	559	2	—	—	—	1,449
Transmission	108	95	80	69	63	427	842
Operating leases and easements	7	6	7	6	5	90	121
Maintenance, service and other contracts	52	25	26	16	8	81	208
Total commitments	$ 2,217	$ 1,548	$ 839	$ 618	$ 538	$ 3,893	$ 9,553

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 $26 million for 2018 and $14 million for 2017.

Included in the minimum fixed annual payments for purchased electricity above are commitments to purchase electricity from several hydroelectric systems under long-term arrangements with public utility districts. These purchases are made on a "cost-of-service" basis for a stated percentage of system output and for a like percentage of system operating expenses and debt service. These costs are included in operation expenses on the Statement of Income. PacifiCorp is required to pay its portion of operating costs and its portion of the debt service, whether or not any electricity is produced. These arrangements accounted for less than 5% of PacifiCorp's 2018 and 2017 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 certain generating plant, 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, 2096. 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, 2018 and 2017.

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 2019, PacifiCorp declared a dividend of $175 million to PPW Holdings LLC, a wholly owned subsidiary of BHE and PacifiCorp's direct parent company ("PPW Holdings"), which was paid in March 2019.

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, 2018, 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. As of December 31, 2018, PacifiCorp's actual common equity percentage, as calculated under this measure, was 54%, and PacifiCorp would have been permitted to dividend $2.6 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, 2018, 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):

	2018	2017
Interest paid, net of amounts capitalized	$ 349	$ 350
Income taxes paid, net[1]	$ 131	$ 331
Supplemental disclosure of non-cash investing and financing activities:		
Accounts payable related to utility plant additions	$ 184	$ 147

(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 paid to BHE.

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 2018/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				(12,594,198)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				548,090
3	Preceding Quarter/Year to Date Changes in Fair Value				(3,220,070)
4	Total (lines 2 and 3)				(2,671,980)
5	Balance of Account 219 at End of Preceding Quarter/Year				(15,266,178)
6	Balance of Account 219 at Beginning of Current Year				(15,266,178)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				696,196
8	Current Quarter/Year to Date Changes in Fair Value				1,934,940
9	Total (lines 7 and 8)				2,631,136
10	Balance of Account 219 at End of Current Quarter/Year				(12,635,042)

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			(12,594,198)		
2			548,090		
3			(3,220,070)		
4			(2,671,980)	768,437,084	765,765,104
5			(15,266,178)		
6			(15,266,178)		
7			696,196		
8			1,934,940		
9			2,631,136	737,709,000	740,340,136
10			(12,635,042)		

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)	27,934,965,226	27,934,965,226
4	Property Under Capital Leases	20,785,264	20,785,264
5	Plant Purchased or Sold		
6	Completed Construction not Classified	286,429,253	286,429,253
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	28,242,179,743	28,242,179,743
9	Leased to Others		
10	Held for Future Use	26,415,220	26,415,220
11	Construction Work in Progress	1,194,168,876	1,194,168,876
12	Acquisition Adjustments	156,468,483	156,468,483
13	Total Utility Plant (8 thru 12)	29,619,232,322	29,619,232,322
14	Accum Prov for Depr, Amort, & Depl	11,032,877,405	11,032,877,405
15	Net Utility Plant (13 less 14)	18,586,354,917	18,586,354,917
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	10,291,136,026	10,291,136,026
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	614,571,348	614,571,348
22	Total In Service (18 thru 21)	10,905,707,374	10,905,707,374
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	127,170,031	127,170,031
33	Total Accum Prov (equals 14) (22,26,30,31,32)	11,032,877,405	11,032,877,405

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 2018/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
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					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 2018/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	209,509,118	769,444
4	(303) Miscellaneous Intangible Plant	727,413,664	39,438,153
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	936,922,782	40,207,597
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	92,989,902	
9	(311) Structures and Improvements	1,029,940,705	13,320,303
10	(312) Boiler Plant Equipment	4,615,243,468	88,931,004
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	983,650,601	25,638,629
13	(315) Accessory Electric Equipment	488,876,291	2,521,295
14	(316) Misc. Power Plant Equipment	32,004,449	3,039,000
15	(317) Asset Retirement Costs for Steam Production	129,737,318	6,182,871
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	7,372,442,734	139,633,102
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	36,312,178	7,926
28	(331) Structures and Improvements	276,902,816	3,847,134
29	(332) Reservoirs, Dams, and Waterways	504,570,856	8,710,528
30	(333) Water Wheels, Turbines, and Generators	132,392,618	6,976,091
31	(334) Accessory Electric Equipment	83,048,610	2,284,407
32	(335) Misc. Power PLant Equipment	2,381,811	881
33	(336) Roads, Railroads, and Bridges	23,901,498	1,267,332
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	1,059,510,387	23,094,299
36	D. Other Production Plant		
37	(340) Land and Land Rights	45,478,205	
38	(341) Structures and Improvements	228,119,279	1,184,759
39	(342) Fuel Holders, Products, and Accessories	16,187,932	269
40	(343) Prime Movers	2,930,921,678	29,254,945
41	(344) Generators	477,502,450	1,530,410
42	(345) Accessory Electric Equipment	327,901,075	1,551,096
43	(346) Misc. Power Plant Equipment	15,906,388	47,709
44	(347) Asset Retirement Costs for Other Production	13,031,355	4,288,740
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	4,055,048,362	37,857,928
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	12,487,001,483	200,585,329

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
673,747			209,604,815		3
6,024,611			760,827,206		4
6,698,358			970,432,021		5
					6
					7
			92,989,902		8
3,650,364			1,039,610,644		9
39,986,727		726,531	4,664,914,276		10
					11
8,143,810			1,001,145,420		12
588,541		-1,107,124	489,701,921		13
1,553,116			33,490,333		14
	-4,661,230		131,258,959		15
53,922,558	-4,661,230	-380,593	7,453,111,455		16
					17
					18
					19
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					23
					24
					25
					26
			36,320,104		27
2,256,915		-54,179	278,438,856		28
1,458,410		54,179	511,877,153		29
898,124			138,470,585		30
529,288			84,803,729		31
8,340			2,374,352		32
194,410			24,974,420		33
					34
5,345,487			1,077,259,199		35
					36
45,316			45,432,889		37
272,645		-312	229,031,081		38
		-26	16,188,175		39
19,475,582		29,482	2,940,730,523		40
388,968		-28,736	478,615,156		41
307,434		-392	329,144,345		42
29,760		-16	15,924,321		43
	-464,880		16,855,215		44
20,519,705	-464,880		4,071,921,705		45
79,787,750	-5,126,110	-380,593	12,602,292,359		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 2018/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	265,463,991	7,592,764
49	(352) Structures and Improvements	257,688,990	18,300,457
50	(353) Station Equipment	2,195,395,245	81,136,003
51	(354) Towers and Fixtures	1,294,996,299	6,290,713
52	(355) Poles and Fixtures	948,225,375	14,415,829
53	(356) Overhead Conductors and Devices	1,237,023,809	19,492,593
54	(357) Underground Conduit	3,519,394	664
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)	6,222,285,657	147,229,023
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	63,696,481	920,970
61	(361) Structures and Improvements	115,852,040	5,122,912
62	(362) Station Equipment	1,023,434,976	27,789,643
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	1,183,290,681	44,813,845
65	(365) Overhead Conductors and Devices	754,957,486	22,936,227
66	(366) Underground Conduit	370,250,464	16,846,056
67	(367) Underground Conductors and Devices	864,063,506	37,506,169
68	(368) Line Transformers	1,349,720,845	50,604,104
69	(369) Services	778,051,452	41,492,046
70	(370) Meters	205,790,437	63,016,074
71	(371) Installations on Customer Premises	8,810,967	72,428
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	62,639,259	1,428,121
74	(374) Asset Retirement Costs for Distribution Plant	1,344,766	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	6,781,903,360	312,548,595
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	21,695,015	12
87	(390) Structures and Improvements	245,730,525	9,323,286
88	(391) Office Furniture and Equipment	82,426,126	20,843,309
89	(392) Transportation Equipment	118,365,919	5,246,656
90	(393) Stores Equipment	15,428,202	541,338
91	(394) Tools, Shop and Garage Equipment	64,895,499	3,041,657
92	(395) Laboratory Equipment	33,392,275	2,089,576
93	(396) Power Operated Equipment	179,487,287	20,020,098
94	(397) Communication Equipment	459,236,333	25,473,312
95	(398) Miscellaneous Equipment	8,319,050	252,613
96	SUBTOTAL (Enter Total of lines 86 thru 95)	1,228,976,231	86,831,857
97	(399) Other Tangible Property	1,854,828	
98	(399.1) Asset Retirement Costs for General Plant	39,748	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	1,230,870,807	86,831,857
100	TOTAL (Accounts 101 and 106)	27,658,984,089	787,402,401
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	27,658,984,089	787,402,401

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
139,171		-17,094	272,900,490		48
114,452			275,874,995		49
10,954,761		124,921	2,265,701,408		50
169,950		38,856	1,301,155,918		51
2,208,214		-12,468	960,420,522		52
2,990,978		-26,389	1,253,499,035		53
			3,520,058		54
			8,035,354		55
			11,937,200		56
					57
16,577,526		107,826	6,353,044,980		58
					59
26,636		-35,611	64,555,204		60
212,427			120,762,525		61
7,616,703		-132,817	1,043,475,099		62
					63
7,345,965			1,220,758,561		64
3,433,947			774,459,766		65
1,938,372			385,158,148		66
3,447,833			898,121,842		67
9,487,157			1,390,837,792		68
1,099,971			818,443,527		69
39,130,829			229,675,682		70
76,913			8,806,482		71
					72
1,179,192			62,888,188		73
			1,344,766		74
74,995,945		-168,428	7,019,287,582		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
154,406			21,540,621		86
4,652,520			250,401,291		87
14,954,083			88,315,352		88
5,904,032		-31,654	117,676,889		89
1,095,137		45,356	14,919,759		90
2,902,044		-1,366,194	63,668,918		91
1,777,009		1,169,183	34,874,025		92
8,088,420		407,870	191,826,835		93
1,767,005		7,896	482,950,536		94
458,960		156,032	8,268,735		95
41,753,616		388,489	1,274,442,961		96
			1,854,828		97
			39,748		98
41,753,616		388,489	1,276,337,537		99
219,813,195	-5,126,110	-52,706	28,221,394,479		100
					101
					102
					103
219,813,195	-5,126,110	-52,706	28,221,394,479		104

Schedule Page: 204 Line No.: 4 Column: b

Includes mining assets related to production plant of $14,654.

Schedule Page: 204 Line No.: 5 Column: b

Adjustment to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, is as follows:

Account (a)	Ref. Line No. (Column)	Balance Beg. of Year (b)
TOTAL Intangible Plant	5(b)	$ 936,922,782
Less: Intangible mining plant(1)		14,654
Revised TOTAL Intangible Plant		$ 936,908,128

(1) To adjust PacifiCorp's formula rate, per FERC Docket No. FA16-4-000 for mining assets related to production plant.

Schedule Page: 204 Line No.: 46 Column: b

Adjustments to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, are as follows:

Account (a)	Ref. Line No. (Column)	Balance Beg. of Year (b)
TOTAL Production Plant	46(b)	$12,487,001,483
Less: (317) Asset Retirement Costs for Steam Production(1)	15(b)	129,737,318
Less: (326) Asset Retirement Costs for Nuclear Production(1)	24(b)	-
Less: (337) Asset Retirement Costs for Hydraulic Production(1)	34(b)	-
Less: (347) Asset Retirement Costs for Other Production(1)	44(b)	13,031,355
Revised TOTAL Production Plant		$12,344,232,810

(1) In accordance with 18 C.F.R. §35.18(a-c) a public utility that files a transmission rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.

Schedule Page: 204 Line No.: 46 Column: g

Adjustments to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, are as follows:

Account (a)	Ref. Line No. (Column)	Balance End of Year (g)
TOTAL Production Plant	46(g)	$12,602,292,359
Less: (317) Asset Retirement Costs for Steam Production(1)	15(g)	131,258,959
Less: (326) Asset Retirement Costs for Nuclear Production(1)	24(g)	-
Less: (337) Asset Retirement Costs for Hydraulic Production(1)	34(g)	-
Less: (347) Asset Retirement Costs for Other Production(1)	44(g)	16,855,215
Revised TOTAL Production Plant		$12,454,178,185

(1) In accordance with 18 C.F.R. §35.18(a-c) a public utility that files a transmission rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.

Schedule Page: 204 Line No.: 75 Column: b

Adjustment to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, is as follows:

Account (a)	Ref. Line No. (Column)	Balance at Beg. of Year (b)
TOTAL Distribution Plant	75(b)	$ 6,781,903,360
Less: (374) Asset Retirement Costs for Distribution Plant(1)	74(b)	1,344,766
Revised TOTAL Distribution Plant		$ 6,780,558,594

(1) In accordance with 18 C.F.R. §35.18(a-c) a public utility that files a transmission rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.

Schedule Page: 204 Line No.: 75 Column: g

Adjustment to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, is as follows:

Account (a)	Ref. Line No. (Column)	Balance at End of Year (g)
TOTAL Distribution Plant	75(g)	$ 7,019,287,582
Less: (374) Asset Retirement Costs for Distribution Plant(1)	74(g)	1,344,766
Revised TOTAL Distribution Plant		$ 7,017,942,816

(1) In accordance with 18 C.F.R. §35.18(a-c) a public utility that files a transmission rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.

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

Account 39921, Land owned in fee

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

Refer to footnote on page 204, line no. 97, column (b)

Schedule Page: 204 Line No.: 99 Column: b

Adjustments to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, are as follows:

Account (a)	Ref. Line No. (Column)	Balance at Beg. of Year (b)
TOTAL General Plant	99(b)	$ 1,230,870,807
Less: (399) Other Tangible Property(1)	97(b)	1,854,828
Less: (399.1) Asset Retirement Costs for General Plant(2)	98(b)	39,748
Revised TOTAL General Plant		$ 1,228,976,231

(1) To adjust PacifiCorp's formula rate, per FERC Docket No. FA16-4-000 for mining assets related to production plant.

(2) In accordance with 18 C.F.R. §35.18(a-c) a public utility that files a transmission rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.

Schedule Page: 204 Line No.: 99 Column: g

Adjustments to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, are as follows:

Account (a)	Ref. Line No. (Column)	Balance at End of Year (g)
TOTAL General Plant	99(g)	$ 1,276,337,537
Less: (399) Other Tangible Property(1)	97(g)	1,854,828
Less: (399.1) Asset Retirement Costs for General Plant(2)	98(g)	39,748
Revised TOTAL General Plant		$ 1,274,442,961

(1) To adjust PacifiCorp's formula rate, per FERC Docket No. FA16-4-000 for mining assets related to production plant.

(2) In accordance with 18 C.F.R. §35.18(a-c) a public utility that files a transmission rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.

Schedule Page: 204 Line No.: 104 Column: b

Adjustments to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, are as follows:

Account (a)	Ref. Line No. (Column)	Balance at Beg. of Year (b)
Revised TOTAL Intangible Plant(1)		$ 936,908,128
Revised TOTAL Production Plant(2)		12,344,232,810
TOTAL Transmission Plant	58(b)	6,222,285,657
Revised TOTAL Distribution Plant(3)		6,780,558,594
Revised TOTAL General Plant(4)		1,228,976,231
(102) Electric Plant Purchased	101(b)	-
(Less) (102) Electric Plant Sold	102(b)	-
(103) Experimental Plant Unclassified	103(b)	-
Revised TOTAL Electric Plant in Service		$27,512,961,420

(1) Refer to footnote on page 204, line no. 5, column (b)
(2) Refer to footnote on page 204, line no. 46, column (b)
(3) Refer to footnote on page 204, line no. 75, column (b)
(4) Refer to footnote on page 204, line no. 99, column (b)

Schedule Page: 204 Line No.: 104 Column: g

Adjustments to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, are as follows:

Account (a)	Ref. Line No. (Column)	Balance at End of Year (g)
TOTAL Intangible Plant	5(g)	$ 970,432,021
Revised TOTAL Production Plant(1)		12,454,178,185
TOTAL Transmission Plant	58(g)	6,353,044,980
Revised TOTAL Distribution Plant(2)		7,017,942,816
Revised TOTAL General Plant(3)		1,274,442,961
(102) Electric Plant Purchased	101(g)	-
(Less) (102) Electric Plant Sold	102(g)	-
(103) Experimental Plant Unclassified	103(g)	-
Revised TOTAL Electric Plant in Service		$28,070,040,963

(1) Refer to footnote on page 204, line no. 46, column (g)
(2) Refer to footnote on page 204, line no. 75, column (g)
(3) Refer to footnote on page 204, line no. 99, column (g)

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 2018/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	2027	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	2024	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	2022	396,020
9	Bend Service Center	2010	2020	3,507,838
10	Legacy Substation	2010	2021	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	Lassen Substation	2012	2019	683,318
15	Old Mill Substation	2012	2026	1,838,281
16	Chimney Butte-Paradise 230kV Transmission Line	2013	2025	598,457
17	Fiddlers Canyon Substation	2016	2028	1,136,587
18	Gateway Area Substation	2017	2023	3,165,831
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				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			26,415,220

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

Land purchased for future development with an estimated utility service date of 2039, subject to business strategy and development plans.

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

Land purchased for future development with an estimated utility service date of 2039, subject to business strategy and development plans.

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

Property is expected to be placed in-service in 2020, as part of the Energy Vision 2020 project, subject to environmental and economic reviews.

Schedule Page: 214 Line No.: 12 Column: c

Property is expected to be placed in-service in 2020, as part of the Energy Vision 2020 project, subject to environmental and economic reviews.

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 2018/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	Energizing Customer Tools Software	5,007,074
3	Mapping System Consolidation Software	1,974,501
4	Prospect No. 3 Hydro Relicensing	1,783,503
5	UI Planner Revenue Model Software	1,677,915
6	Weber Hydro Relicensing	1,205,066
7	Generation Optimization Software: Power Costs, Inc.	1,027,882
8	Production:	
9	Wind Repowering/Safe Harbor Equipment Purchases**	129,565,185
10	Seven Mile Hill Wind Repowering**	87,606,141
11	Glenrock Wind Repowering**	82,301,645
12	Leaning Juniper 1 Wind Repowering**	28,849,199
13	Marengo Wind Repowering**	24,302,848
14	Dunlap Ranch 1 Wind Repowering**	23,506,482
15	High Plains Wind Repowering**	20,958,237
16	Seven Mile Hill II Wind Repowering**	16,814,076
17	Goodnoe Hills Wind Repowering**	15,446,544
18	Rolling Hills Wind Repowering**	15,359,195
19	Marengo II Wind Repowering**	11,955,064
20	Lewis River System Relicensing Implementation	9,297,610
21	Glenrock III Wind Repowering**	6,317,931
22	TB Flats Wind Project 500 MW**	5,368,537
23	Colstrip U3 and U4: Water Management System	3,713,077
24	Ekola Flats Wind Project 250 MW**	3,140,377
25	Toketee Dam Rehabilitation Evaluation	3,004,236
26	Merwin Spillway Gate Wood Extension Replacement	2,533,200
27	Lewis River System Maximum Flood Improvement Study	2,171,070
28	Dave Johnston Ash Disposal System, Coal Combustion Residual	1,716,383
29	Cedar Springs Wind Project 200 MW**	1,296,173
30	Dave Johnston Waste Ash Silo Modifications	1,243,913
31	Huntington U2 Boiler Economizer and Inlet Heater Replacement	1,228,789
32	Soda Hydro Spinning Reserve	1,208,124
33	Foote Creek Wind Repowering**	1,214,648
34	Jim Bridger U3 Catalyst Replacement, Selective Catalytic Reduction System	1,138,712
35	Dave Johnston Coal Yard Control System Update	1,108,001
36	Huntington Electric Lake Dam Outlet Upgrade	1,041,275
37	Bear River Hydro Flood and Structural Assessment Project	1,016,209
38	Transmission:	
39	Aeolus - Bridger/Anticline 500kV Line**	98,792,466
40	Aeolus - Mona 500kV Line	95,739,929
41	Boardman - Hemingway 500kV Line	70,587,478
42	Populus - Hemingway 500kV Line	60,425,148
43	TOTAL	1,194,168,876

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 2018/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	Windstar - Populus 230 - 500kV Line	54,680,076
2	Wallula - McNary 230kV Line	31,395,882
3	Vantage - Pomona Heights 230kV Line	27,727,351
4	Delta Fire Damaged Facilities	15,361,335
5	Oquirrh - Terminal 345kV Line	14,070,180
6	Rexburg Substation - Install 161kV Source from Rigby	11,705,848
7	Sams Valley New 500 - 230kV Substation	6,916,269
8	Generation Interconnection (Cedar Springs 1, TB Flats and Ekola Flats)**	6,461,838
9	Jordanelle - Midway 138kV Line	4,251,594
10	Goshen - Sugarmill - Rigby 161kV Line	3,766,609
11	Goshen Substation Install 3rd 345 - 161kV 700 MVA Transformer TPL	3,373,606
12	Rigby & Sugarmill 161kV Substation Shunt Capacitors	2,220,201
13	Grace Substation: Relocate 46kV Line	1,745,520
14	Huntington U2 Generator Step-Up Transformer Replacement	1,563,088
15	NE Portland Voltage Conversion Project - Transmission Lines and Substations	1,089,689
16	Yreka Substation 115 - 69kV Transformer Addition	1,069,262
17	Dave Johnston - Thunder Creek 57 - 69kV System Conversion	1,041,394
18	Distribution:	
19	Utah Advanced Metering Infrastructure	9,750,807
20	Jackalope Substation Install 2nd Transformer, Remove Douglas Town Sub	4,860,287
21	Naples New 138 - 12.5kV Substation TPL	4,190,668
22	Lassen Substation - New Substation	3,838,714
23	Herriman Substation Install 2nd 138 - 12.5kV Transformer	3,795,355
24	Jordan Valley Underground Cable Testing and Replacement Project	3,597,434
25	Boise White Paper, LLC Interconnect Load Addition	2,868,862
26	Ivins Substation Replace Transformer	2,195,822
27	Idaho Advanced Metering Infrastructure	1,755,852
28	Stadion, LLC New Load Addition	1,705,431
29	Oregon - Mandated Neutral Extensions - Roseburg	1,287,034
30	General:	
31	North Temple Office Parking Lot Upgrade	1,278,821
32	Replacement of DMX Fiber Optic Communications Infrastructure/Equip - Jordan Valley Area	1,167,563
33		
34	Miscellaneous Projects each under $1,000,000	120,792,641
35		
36	** Energy Vision 2020 projects	
37		
38		
39		
40		
41		
42		
43	TOTAL	1,194,168,876

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 2018/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	9,599,722,773	9,599,722,773		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	908,461,901	908,461,901		
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):	22,089,061	22,089,061		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	930,550,962	930,550,962		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	210,218,153	210,218,153		
13	Cost of Removal	40,800,230	40,800,230		
14	Salvage (Credit)	6,272,294	6,272,294		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	244,746,089	244,746,089		
16	Other Debit or Cr. Items (Describe, details in footnote):	5,608,380	5,608,380		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	10,291,136,026	10,291,136,026		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	3,633,335,055	3,633,335,055		
21	Nuclear Production				
22	Hydraulic Production-Conventional	421,162,472	421,162,472		
23	Hydraulic Production-Pumped Storage				
24	Other Production	1,138,023,509	1,138,023,509		
25	Transmission	1,768,071,124	1,768,071,124		
26	Distribution	2,848,002,466	2,848,002,466		
27	Regional Transmission and Market Operation				
28	General	482,541,400	482,541,400		
29	TOTAL (Enter Total of lines 20 thru 28)	10,291,136,026	10,291,136,026		

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	$ 198,484
Account 182.3, Other regulatory assets or Account 254, Other regulatory liabilities: asset retirement obligations asset depreciation	10,484,921
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	(1,365,393)
Transportation depreciation charged to operations and maintenance expense and construction work in progress based on usage activity	15,829,896
Account 503, Steam from other sources: Blundell depreciation	2,022,621
Total Other Accounts	$ 22,089,061

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	$ 1,533,843
Other items include: - Recovery from third parties for asset relocations and damaged properties - Insurance recoveries - Adjustments of reserve related to electric plant sold and/or purchased - Reclassifications from electric plant	4,074,537
Total Other Debit or Cr. Items	$ 5,608,380

Schedule Page: 219 Line No.: 20 Column: c

Adjustment to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, is as follows:

Item (a)	Ref. Line No. (Column)	Electric Plant in Service (c)
Steam Production	20(c)	$ 3,633,335,055
Less: Asset retirement obligations related cost components(1)		50,651,697
Revised Steam Production		$ 3,582,683,358

(1) In accordance with 18 C.F.R. §35.18(a-c) a public utility that files a transmission rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.

Schedule Page: 219 Line No.: 22 Column: c

Adjustment to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, is as follows:

Item (a)	Ref. Line No. (Column)	Electric Plant in Service (c)
Hydraulic Production - Conventional	22(c)	$ 421,162,472
Less: Asset retirement obligations related cost components(1)		2,665,237
Revised Hydraulic Production - Conventional		$ 418,497,235

(1) In accordance with 18 C.F.R. §35.18(a-c) a public utility that files a transmission rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.

Schedule Page: 219 Line No.: 24 Column: c

Adjustment to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, is as follows:

Item (a)	Ref. Line No. (Column)	Electric Plant in Service (c)
Other Production	24(c)	$ 1,138,023,509
Less: Asset retirement obligations related cost components(1)		(2,422,685)
Revised Other Production		$ 1,140,446,194

(1) In accordance with 18 C.F.R. §35.18(a-c) a public utility that files a transmission rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.

Schedule Page: 219 Line No.: 25 Column: c

Adjustment to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, is as follows:

Item (a)	Ref. Line No. (Column)	Electric Plant in Service (c)
Transmission	25(c)	$ 1,768,071,124
Less: Asset retirement obligations related cost components(1)		(460,501)
Revised Transmission		$ 1,768,531,625

(1) In accordance with 18 C.F.R. §35.18(a-c) a public utility that files a transmission rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.

Schedule Page: 219 Line No.: 26 Column: c

Adjustment to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, is as follows:

Item (a)	Ref. Line No. (Column)	Electric Plant in Service (c)
Distribution	26(c)	$ 2,848,002,466
Less: Asset retirement obligations related cost components(1)		851,802
Revised Distribution		$ 2,847,150,664

(1) In accordance with 18 C.F.R. §35.18(a-c) a public utility that files a transmission rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.

Schedule Page: 219 Line No.: 28 Column: c

Adjustment to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, is as follows:

Item (a)	Ref. Line No. (Column)	Electric Plant in Service (c)
General	28(c)	$ 482,541,400
Less: Asset retirement obligations related cost components(1)		(185,927)
Revised General		$ 482,727,327

(1) In accordance with 18 C.F.R. §35.18(a-c) a public utility that files a transmission rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.

Schedule Page: 219 Line No.: 29 Column: c

Adjustments to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, are as follows:

Item (a)	Ref. Line No. (Column)	Electric Plant in Service (c)
Revised Steam Production(1)		$ 3,582,683,358
Nuclear Production	21(c)	-
Revised Hydraulic Production - Conventional(2)		418,497,235
Hydraulic Production - Pumped Storage	23(c)	-
Revised Other Production(3)		1,140,446,194
Revised Transmission(4)		1,768,531,625
Revised Distribution(5)		2,847,150,664
Regional Transmission and Market Operation	27(c)	-
Revised General(6)		482,727,327
Revised TOTAL		$10,240,036,403

(1) Refer to footnote on page 219, line no. 20, column (c)
(2) Refer to footnote on page 219, line no. 22, column (c)
(3) Refer to footnote on page 219, line no. 24, column (c)
(4) Refer to footnote on page 219, line no. 25, column (c)
(5) Refer to footnote on page 219, line no. 26, column (c)
(6) Refer to footnote on page 219, line no. 28, column (c)

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 2018/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			96,606,077
5	SUBTOTAL			144,566,078
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			7,730,250
22	SUBTOTAL			13,768,250
23				
24	Fossil Rock Fuels, LLC	2011		
25	Paid-in Capital			27,669,770
26	Undistributed Subsidiary Earnings			968
27	SUBTOTAL			27,670,738
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 79,001,772		TOTAL	186,007,067

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
17,774,578		96,380,655		4
17,774,578		144,340,656		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
432,521		8,017,743		21
432,521		14,055,743		22
				23
				24
		25,001,770		25
2,662,879		847		26
2,662,879		25,002,617		27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
20,869,978		183,401,017		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. Bridger Coal Company is a coal mining joint venture with Idaho Energy Resources Company, a subsidiary of Idaho Power Company.

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

During the year ended December 31, 2018, Pacific Minerals, Inc., a wholly owned subsidiary of PacifiCorp, paid a dividend of $18,000,000 to PacifiCorp.

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

During the year ended December 31, 2018, Trapper Mining Inc., a subsidiary of PacifiCorp, paid a dividend of $145,028 to PacifiCorp.

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

During the year ended December 31, 2018, Fossil Rock Fuels, LLC, a wholly owned subsidiary of PacifiCorp, returned $2,668,000 of capital to PacifiCorp.

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

During the year ended December 31, 2018, Fossil Rock Fuels, LLC, a wholly owned subsidiary of PacifiCorp, paid distributions of $2,663,000 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)	197,499,391	179,588,705	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)	150,015,776	161,139,297	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	73,975,748	63,541,336	Electric
8	Transmission Plant (Estimated)	381,386	786,256	Electric
9	Distribution Plant (Estimated)	10,875,356	12,201,122	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	28,604	26,420	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	235,276,870	237,694,431	
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)	432,776,261	417,283,136	

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 2018/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)	2019 No. (d)	2019 Amt. (e)
1	Balance-Beginning of Year	811,485.00		151,417.00	
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	25,925.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	785,560.00		151,417.00	
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 2018/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.

2020		2021		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
156,646.00		156,646.00		4,072,758.00		5,348,952.00		1
								2
								3
				156,644.00		156,644.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						25,925.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
156,646.00		156,646.00		4,229,402.00		5,479,671.00		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 2018/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	Q1977	3,343	561.6	3,343	456
3	Q2144	149	561.6		
4	Q2292	149	561.6	149	456
5	Q2370	116	561.6	116	456
6	Q2409	1,455	561.6	1,455	456
7	Q2422	612	561.6		
8	Q2424	1,191	561.6		
9	Q2427	3,985	561.6	3,985	456
10	Q2435	12,495	561.6	4,185	456
11	Q2455	3,107	561.6	2,146	456
12	Q2467	3,067	561.6		
13	Q2469	7,145	561.6		
14	Q2471	5,635	561.6		
15	Q2472	4,326	561.6		
16	Q2486	149	561.6		
17	Q2487	1,057	561.6	1,057	456
18	Q2488	594	561.6	594	456
19	Q2497	149	561.6		
20	Q2498	2,927	561.6		
21	**Generation Studies**				
22	GIQ0409	11,560	561.7	11,560	456
23	GIQ0650	4,052	561.7	4,052	456
24	GIQ0687	77,415	561.7	77,415	456
25	GIQ0707	11,520	561.7	11,520	456
26	GIQ0708	9,248	561.7	12,002	456
27	GIQ0712	17,743	561.7	17,743	456
28	GIQ0713	4,625	561.7	4,625	456
29	GIQ0715	13,010	561.7	13,010	456
30	GIQ0718	25,028	561.7	25,028	456
31	GIQ0719	10,894	561.7	10,894	456
32	GIQ0731	4,988	561.7	4,988	456
33	GIQ0734	5,527	561.7	5,527	456
34	GIQ0737	8,292	561.7	8,292	456
35	GIQ0738	12,326	561.7	12,326	456
36	GIQ0739	6,194	561.7	6,194	456
37	GIQ0745	9,985	561.7	9,985	456
38	GIQ0752	79	561.7	79	456
39	GIQ0753	454	561.7	454	456
40	GIQ0754	2,055	561.7	2,055	456

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	Q2499	5,242	561.6		
3	Q2500	2,155	561.6		
4	Q2504	3,706	561.6	3,706	456
5	Q2505	4,237	561.6	4,237	456
6	Q2517	149	561.6		
7	Q2518	7,558	561.6		
8	Q2527	1,075	561.6		
9	Q2528	3,853	561.6		
10	Order 45045642	10,559	561.6	10,559	456
11	AREF 84879085	926	561.6		
12	AREF 84879111	926	561.6		
13	Customer Studies Accruals	10,911	561.6		
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	GIQ0763	11,554	561.7	11,554	456
23	GIQ0764	3,374	561.7	3,374	456
24	GIQ0766	19,251	561.7	19,251	456
25	GIQ0777	6,393	561.7	6,393	456
26	GIQ0778	7,422	561.7	7,422	456
27	GIQ0781	3,762	561.7	3,762	456
28	GIQ0783	8,423	561.7	8,423	456
29	GIQ0784	5,940	561.7	5,940	456
30	GIQ0785	5,614	561.7	5,519	456
31	GIQ0786	16,550	561.7	16,559	456
32	GIQ0787	18,575	561.7	18,575	456
33	GIQ0788	24,300	561.7	24,300	456
34	GIQ0789	7,823	561.7	7,823	456
35	GIQ0792	16,256	561.7	16,345	456
36	GIQ0799	25,498	561.7	25,498	456
37	GIQ0801	2,953	561.7	2,953	456
38	GIQ0802	13,646	561.7	13,646	456
39	GIQ0803	16,534	561.7	16,534	456
40	GIQ0804	16,422	561.7	16,422	456

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	GIQ0805	23,038	561.7	23,038	456
23	GIQ0806	79	561.7	79	456
24	GIQ0807	12,848	561.7	12,848	456
25	GIQ0810	19,929	561.7	19,929	456
26	GIQ0811	25,033	561.7	25,122	456
27	GIQ0815	12,660	561.7	12,749	456
28	GIQ0819	10,699	561.7	10,699	456
29	GIQ0820	7,274	561.7		
30	GIQ0821	13,191	561.7		
31	GIQ0822	9,336	561.7		
32	GIQ0823	7,978	561.7		
33	GIQ0824	13,854	561.7	13,854	456
34	GIQ0825	13,212	561.7	13,212	456
35	GIQ0835	22,120	561.7	22,120	456
36	GIQ0836	7,441	561.7	7,441	456
37	GIQ0838	11,154	561.7	11,154	456
38	GIQ0839	545	561.7	545	456
39	GIQ0840	6,031	561.7	6,031	456
40	GIQ0846	5,403	561.7	5,403	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 2018/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	GIQ0849	12,415	561.7	12,415	456
23	GIQ0850	12,535	561.7	12,535	456
24	GIQ0852	675	561.7	675	456
25	GIQ0853	19,692	561.7	19,692	456
26	GIQ0855	19,648	561.7	19,648	456
27	GIQ0856	(11,801)	561.7	(11,801)	456
28	GIQ0856	12,820	561.7		
29	GIQ0858	(5,570)	561.7	(5,570)	456
30	GIQ0858	8,645	561.7		
31	GIQ0859	(3,874)	561.7	(3,874)	456
32	GIQ0859	9,877	561.7		
33	GIQ0860	(1,733)	561.7	(1,733)	456
34	GIQ0860	6,831	561.7		
35	GIQ0861	(1,293)	561.7	(1,293)	456
36	GIQ0861	5,562	561.7		
37	GIQ0862	13,690	561.7	13,690	456
38	GIQ0863	(2,200)	561.7	(2,200)	456
39	GIQ0863	19,030	561.7		
40	GIQ0864	72	561.7	72	456

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
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21	**Generation Studies**				
22	GIQ0865	72	561.7	72	456
23	GIQ0866	161	561.7	161	456
24	GIQ0867	79	561.7	79	456
25	GIQ0868	25,004	561.7	25,004	456
26	GIQ0871	196	561.7	196	456
27	GIQ0872	562	561.7	562	456
28	GIQ0875	20	561.7	20	456
29	GIQ0876	(716)	561.7	(716)	456
30	GIQ0876	836	561.7		
31	GIQ0877	58,861	561.7	58,861	456
32	GIQ0880	182	561.7	182	456
33	GIQ0882	100	561.7	100	456
34	GIQ0883	20	561.7	20	456
35	GIQ0888	6,124	561.7	6,124	456
36	GIQ0893	7,091	561.7	7,091	456
37	GIQ0894	111	561.7	111	456
38	GIQ0895	3,033	561.7	3,033	456
39	GIQ0897	145	561.7	145	456
40	GIQ0898	238	561.7	238	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	GIQ0904	13,226	561.7	13,226	456
23	GIQ0905	13,065	561.7	13,065	456
24	GIQ0906	25,735	561.7	25,735	456
25	GIQ0907	21,709	561.7	21,709	456
26	GIQ0909	19,556	561.7	19,556	456
27	GIQ0911	5,621	561.7	5,852	456
28	GIQ0914	(6,232)	561.7	(6,232)	456
29	GIQ0914	7,704	561.7		
30	GIQ0915	17,631	561.7	17,631	456
31	GIQ0916	14,157	561.7	14,157	456
32	GIQ0917	11,268	561.7	11,268	456
33	GIQ0918	(4,470)	561.7	(4,470)	456
34	GIQ0918	14,356	561.7		
35	GIQ0919	(2,981)	561.7	(2,981)	456
36	GIQ0919	12,028	561.7		
37	GIQ0923	948	561.7	948	456
38	GIQ0937	40	561.7	40	456
39	GIQ0941	16,707	561.7	16,707	456
40	GIQ0946	10,413	561.7	10,413	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	GIQ0950	20	561.7	20	456
23	GIQ0951	20	561.7	20	456
24	GIQ0953	19,283	561.7	19,283	456
25	GIQ0954	286	561.7	286	456
26	GIQ0955	12,007	561.7	12,007	456
27	GIQ0956	27,911	561.7	27,911	456
28	GIQ0957	13,776	561.7	18,722	456
29	GIQ0958	17,687	561.7	17,687	456
30	GIQ0959	131	561.7	131	456
31	GIQ0960	4,777	561.7	4,777	456
32	GIQ0961	237	561.7	237	456
33	GIQ0962	13,524	561.7	13,524	456
34	GIQ0963	3,265	561.7	3,265	456
35	GIQ0964	3,063	561.7	3,063	456
36	GIQ0965	315	561.7	315	456
37	GIQ0967	15,031	561.7	15,031	456
38	GIQ0968	9,506	561.7	9,506	456
39	GIQ0969	6,411	561.7	6,411	456
40	GIQ0970	5,112	561.7	5,112	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 2018/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	GIQ0971	14,751	561.7	14,751	456
23	GIQ0973	2,499	561.7	2,499	456
24	GIQ0974	20,136	561.7	20,136	456
25	GIQ0976	512	561.7	512	456
26	GIQ0977	293	561.7	293	456
27	GIQ0978	609	561.7	609	456
28	GIQ0979	317	561.7	317	456
29	GIQ0980	949	561.7	949	456
30	GIQ0981	754	561.7	754	456
31	GIQ0982	566	561.7	622	456
32	GIQ0983	682	561.7	893	456
33	GIQ0984	683	561.7	683	456
34	GIQ0985	132	561.7	132	456
35	GIQ0986	1,228	561.7	1,228	456
36	GIQ0987	56,475	561.7	56,475	456
37	GIQ0988	459	561.7	459	456
38	GIQ0989	17,777	561.7	17,777	456
39	GIQ0990	8,533	561.7	8,533	456
40	GIQ0991	222	561.7	222	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 2018/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	GIQ0992	13,479	561.7	13,479	456
23	GIQ0993	2,072	561.7	2,072	456
24	GIQ0994	1,107	561.7	1,107	456
25	GIQ0995	994	561.7	994	456
26	GIQ0996	2,185	561.7	2,185	456
27	GIQ0997	1,729	561.7	1,729	456
28	GIQ0998	1,439	561.7	1,439	456
29	GIQ0999	18,077	561.7	18,077	456
30	GIQ1000	1,287	561.7	1,287	456
31	GIQ1001	12,840	561.7	12,840	456
32	GIQ1002	10,764	561.7	10,764	456
33	GIQ1003	11,493	561.7	11,589	456
34	GIQ1004	1,446	561.7	1,542	456
35	GIQ1005	1,476	561.7	1,476	456
36	GIQ1006	1,156	561.7	1,156	456
37	GIQ1007	7,427	561.7	7,427	456
38	GIQ1008	14,753	561.7	14,753	456
39	GIQ1009	5,606	561.7	5,694	456
40	GIQ1010	1,803	561.7	1,803	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	GIQ1011	855	561.7	855	456
23	GIQ1012	8,317	561.7	8,317	456
24	GIQ1013	981	561.7	981	456
25	GIQ1014	756	561.7	756	456
26	GIQ1015	670	561.7	670	456
27	GIQ1016	620	561.7	620	456
28	GIQ1017	937	561.7	937	456
29	GIQ1018	1,023	561.7	1,023	456
30	GIQ1019	15,281	561.7	15,281	456
31	GIQ1020	8,992	561.7	8,992	456
32	GIQ1021	1,000	561.7	1,000	456
33	GIQ1022	9,861	561.7	9,861	456
34	GIQ1023	13,568	561.7	13,568	456
35	GIQ1024	846	561.7	846	456
36	GIQ1025	1,299	561.7	1,299	456
37	GIQ1026	3,328	561.7		
38	GIQ1027	971	561.7	971	456
39	GIQ1028	859	561.7	859	456
40	GIQ1029	26,688	561.7	26,688	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	GIQ1030	4,778	561.7	4,778	456
23	GIQ1031	17,422	561.7	17,422	456
24	GIQ1032	8,858	561.7	8,858	456
25	GIQ1033	7,038	561.7	7,038	456
26	GIQ1034	17,438	561.7	17,438	456
27	GIQ1035	995	561.7	995	456
28	GIQ1036	653	561.7	653	456
29	GIQ1037	968	561.7		
30	GIQ1038	1,174	561.7	1,174	456
31	GIQ1039	1,497	561.7	1,497	456
32	GIQ1040	1,093	561.7	1,093	456
33	GIQ1041	761	561.7	761	456
34	GIQ1042	416	561.7	416	456
35	GIQ1043	12,122	561.7	12,122	456
36	GIQ1044	1,150	561.7	1,150	456
37	GIQ1045	9,012	561.7	9,012	456
38	GIQ1046	930	561.7	930	456
39	GIQ1047	1,100	561.7	1,100	456
40	GIQ1048	876	561.7	966	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	GIQ1049	1,172	561.7	1,172	456
23	GIQ1050	855	561.7	855	456
24	GIQ1051	802	561.7	802	456
25	GIQ1052	741	561.7	741	456
26	GIQ1053	1,414	561.7	1,414	456
27	GIQ1054	1,172	561.7	1,172	456
28	GIQ1055	7,476	561.7	7,476	456
29	GIQ1056	1,527	561.7	1,527	456
30	GIQ1057	1,007	561.7	1,007	456
31	GIQ1058	830	561.7	830	456
32	GIQ1059	926	561.7	926	456
33	GIQ1060	815	561.7	815	456
34	GIQ1061	628	561.7	628	456
35	GIQ1062	1,082	561.7	1,082	456
36	GIQ1063	8,713	561.7	8,713	456
37	GIQ1064	1,224	561.7	1,224	456
38	GIQ1065	1,558	561.7	1,558	456
39	GIQ1066	120	561.7	120	456
40	GIQ1067	240	561.7	240	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	GIQ1068	1,083	561.7	1,083	456
23	GIQ1069	690	561.7	690	456
24	GIQ1070	1,128	561.7	1,128	456
25	GIQ1071	724	561.7	724	456
26	GIQ1072	423	561.7	423	456
27	GIQ1073	1,244	561.7	1,244	456
28	GIQ1074	1,125	561.7	1,125	456
29	GIQ1075	566	561.7	566	456
30	GIQ1076	1,153	561.7	1,153	456
31	GIQ1077	712	561.7	712	456
32	GIQ1078	1,057	561.7	1,057	456
33	GIQ1079	549	561.7	549	456
34	GIQ1080	1,065	561.7	1,065	456
35	GIQ1081	830	561.7	830	456
36	GIQ1082	40	561.7	40	456
37	GIQ1083	992	561.7	992	456
38	GIQ1084	1,057	561.7	1,057	456
39	GIQ1085	942	561.7	942	456
40	GIQ1086	1,408	561.7	1,408	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	GIQ1087	865	561.7	865	456
23	GIQ1088	227	561.7	227	456
24	GIQ1089	689	561.7	689	456
25	GIQ1090	511	561.7	511	456
26	GIQ1091	471	561.7	471	456
27	GIQ1092	187	561.7	187	456
28	GIQ1093	67	561.7	67	456
29	GIQ1094	270	561.7	270	456
30	GIQ1095	231	561.7	231	456
31	Pre-Application Studies - East	8,131	561.7	8,131	456
32	Pre-Application Studies - West	23,572	561.7	23,572	456
33	Customer Studies Accruals	137	561.7		
34					
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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 2018/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	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter /Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	DSM Balancing Account - UT	4,369,016	7,686,878	908	12,055,894	
2	DSM Balancing Account - WA	143,585	11,117,888	908	11,261,473	
3	DSM Balancing Account - WY	5,509,914	7,666,122	908	4,588,755	8,587,281
4	Irrigation Load Control - OR	57,874	171,816	908	132,857	96,833
5	Deferred Excess Net Power Costs - CA	3,503,556	4,504,759	555	1,998,703	6,009,612
6	Deferred Excess Net Power Costs - ID	9,484,694	16,550,448	555	7,858,159	18,176,983
7	Deferred Excess Net Power Costs - UT	7,559,200	24,647,749	182.3,555	1,835,185	30,371,764
8	Deferred Excess Net Power Costs - WY		5,512,772			5,512,772
9	Deferred Excess RECs in Rates - UT	83,476	1,301,344	456	346,278	1,038,542
10	Deferred Excess RECs in Rates - WY	447,138	453,300	456	136,214	764,224
11	Solar ITC Basis Adjustment Regulatory Asset	38,157	336	282,283	2,243	36,250
12	Pension	417,595,160	40,330,898		15,454,832	442,471,226
13	Other Postretirement		5,713,302			5,713,302
14	Postemployment Costs	1,338,783			476,510	862,273
15	Powerdale Decommissioning - ID (10)	77,714		407.3	25,986	51,728
16	Carbon Plant Regulatory Asset - ID (6)	1,435,915		403	478,639	957,276
17	Carbon Plant Regulatory Asset - UT (6)	10,333,924		403	3,444,641	6,889,283
18	Carbon Plant Regulatory Asset - WY (6)	3,474,563		403	1,158,188	2,316,375
19	Carbon Plant Inventory Regulatory Asset	3,118,823				3,118,823
20	Depreciation Study Deferral - ID (1)	4,133,277		254,403	4,133,277	
21	Depreciation Study Deferral - UT (17)	1,728,583		403	128,043	1,600,540
22	Depreciation Study Deferral - WY (17)	5,969,577		403	442,191	5,527,386
23	Generating Plant Liquidated Damages - UT	560,000		557	35,000	525,000
24	Generating Plant Liquidated Damages - WY	1,244,416		557	54,288	1,190,128
25	Klamath Hydroelectric Relicensing Costs - UT (10)	19,242,000	717,344	404	4,287,002	15,672,342
26	Washington Colstrip Unit No. 3 (22)	160,943		456	52,188	108,755
27	Environmental Costs (10)	78,782,525	8,763,098		4,989,809	82,555,814
28	Asset Retirement Obligations Regulatory Difference	99,883,911	18,769,218			118,653,129
29	Unamortized Contract Values	88,808,488		242	10,056,772	78,751,716
30	Unrealized Loss on Derivative Contracts	101,301,707		175,244	5,523,824	95,777,883
31	Solar Feed-In Tariff Deferral - OR (1)	5,329,132	5,314,733	908	5,518,070	5,125,795
32	Solar Incentive Subscriber Program - UT	1,550,999	237,007	908	124,683	1,663,323
33	Renewable Portfolio Standards Compliance - OR (1)	301,244	465,382	555	651,527	115,099
34	Renewable Portfolio Standards Compliance - WA (1)	32,986	167,371	555	152,528	47,829
35	Protocol - MSP Deferral - ID		150,000			150,000
36	Protocol - MSP Deferral - UT	4,400,000	4,400,000			8,800,000
37	Protocol - MSP Deferral - WY	799,998	1,600,000			2,399,998
38	Deferred Intervenor Funding Grants - CA	41,019	976			41,995
39	Deferred Intervenor Funding Grants - ID	26,865	40,000			66,865
40	Deferred Intervenor Funding Grants - OR	535,508	391,443			926,951
41	Catastrophic Event Regulatory Asset - CA (2)		3,196,502	924	1,017,091	2,179,411
42	Alternative Rate for Energy (CARE) - CA	524,500	93,657	142	336,534	281,623
43	Deferred Overburden Cost - ID	354,223	1,497,748	501	1,358,477	493,494

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 2018/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 Overburden Cost - WY	996,686	4,214,280	501	3,822,401	1,388,565
2	BPA Balancing Account - OR	6,146,695	982,639			7,129,334
3	Property Sales Balancing Account - OR	322,970	1,244,036		482,540	1,084,466
4	Property Insurance Reserve - OR	6,687,383	3,434,414	924	7,068,568	3,053,229
5	Misc. Regulatory Assets/Liabilities - OR	265,573	192			265,765
6	Depreciation Deferral - WA	6,648				6,648
7	Utah Mine Disposition	155,911,213	1,511,235		19,548,225	137,874,223
8	Preferred Stock Redemption Loss - UT (10)	512,377		407.3	82,529	429,848
9	Preferred Stock Redemption Loss - WA (10)	82,126		407.3	13,318	68,808
10	Preferred Stock Redemption Loss - WY (10)	176,575		407.3	28,442	148,133
11	Mobile Home Park Conversion - CA	73,822	124,888			198,710
12	Transportation Electrification Program - OR		48,792			48,792
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44	**TOTAL :**	1,055,465,461	183,022,567		131,161,884	1,107,326,144

Schedule Page: 232 Line No.: 5 Column: a
Weighted average remaining life is approximately one year for deferred excess net power cost mechanisms being amortized.

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

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

Schedule Page: 232 Line No.: 9 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.: 10 Column: a
Weighted average remaining life is approximately one year for deferred excess renewable energy credits in rates being amortized.

Schedule Page: 232 Line No.: 12 Column: a
Weighted average remaining life being amortized is 20 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.: 12 Column: d
Pensions are associated with labor and generally charged to operations and maintenance expense and construction work in progress. Pension settlements, curtailments and remeasurement date changes are charged to Account 926, Employee pensions and benefits.

Schedule Page: 232 Line No.: 14 Column: a
Weighted average remaining life is five years.

Schedule Page: 232 Line No.: 14 Column: d
Other postemployment costs are associated with labor and generally charged to operations and maintenance expense and construction work in progress.

Schedule Page: 232 Line No.: 23 Column: a
Weighted average remaining life is 15 years.

Schedule Page: 232 Line No.: 24 Column: a
Weighted average remaining life is 24 years.

Schedule Page: 232 Line No.: 27 Column: d
Account 514, Maintenance of miscellaneous steam plant
Account 545, Maintenance of miscellaneous hydraulic plant
Account 554, Maintenance of miscellaneous other power generation plant
Account 598, Maintenance of miscellaneous distribution plant

Schedule Page: 232 Line No.: 29 Column: a
Weighted average remaining life is five years. Represents frozen values of contracts previously accounted for as derivatives and recorded at fair value.

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

Schedule Page: 232.1 Line No.: 3 Column: d
Account 182.3, Other regulatory assets
Account 421.1, Gain on disposition of property
Account 431, Other interest expense

Schedule Page: 232.1 Line No.: 7 Column: a
Weighted average remaining life is approximately one year 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 four years for closure costs incurred to date considered probable of recovery.

Schedule Page: 232.1 Line No.: 7 Column: d

Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 501, Fuel
Account 506, Miscellaneous steam power expenses

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)	11,447		557	11,447	
2	Lacomb Irrigation (24)	186,690		557	45,720	140,970
3	Bogus Creek (41)	911,600		557	41,280	870,320
4	Mead Phoenix Availability and					
5	Transmission Charge (46)	11,008,487		565	574,404	10,434,083
6	TGS Buyout (23)	32,236		557	15,473	16,763
7	Point-to-Point Transmission	971,032	8,000			979,032
8	Hermiston Swap (40)	3,190,630		557	171,693	3,018,937
9	Deferred Coal Costs - Wyodak					
10	Settlement (22)	1,675,908		501	335,182	1,340,726
11	LT Lease Commissions Prepaid	148,463		931	41,568	106,895
12	Lake Side Maintenance Prepaid	16,223,296	5,458,631			21,681,927
13	Lake Side 2 Maintenance Prepaid	17,216,022	6,466,792	107	14,963,558	8,719,256
14	Chehalis Maintenance Prepaid	9,381,583	3,430,701			12,812,284
15	Currant Creek Maint. Prepaid	6,151,363	4,951,840			11,103,203
16	Lease Incentives	7,995		454	7,995	
17	Credit Agreement Costs	1,732,495	841,045	427,431	724,166	1,849,374
18	PCRB LOC/SBBPA Costs (2)	3,222		427	2,578	644
19	PCRB Mode Conversion Costs	308,126	67,500	427	90,394	285,232
20	'94 Series Restruct. Costs (16)	401,590		427	58,769	342,821
21	Deferred S-3 Shelf Regis. Costs	191,902	208,464	181	86,899	313,467
22	BPA LT Transmission Prepaid	2,211,329	126,309	565	966,444	1,371,194
23	Emission Reduction Credits	306,510				306,510
24	Unamortized Contract Values	3,643,532	3,646,848			7,290,380
25	Sales of Electric Utility					
26	Facilities & Properties	147,933		539	86,693	61,240
27	IT Licenses and Maint. Prepaid	96,320	75,000	921,923	42,640	128,680
28	Other Deferred Charges		2,071			2,071
29						
30						
31						
32						
33						
34						
35						
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	76,159,711				83,176,009

Schedule Page: 233 Line No.: 11 Column: a

The weighted average remaining life is three years.

Schedule Page: 233 Line No.: 16 Column: a

The weighted average remaining life is one year.

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

The weighted average remaining life is three years.

Schedule Page: 233 Line No.: 19 Column: a

The weighted average remaining life is four years.

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 2018/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	84,332,107	91,494,740
3	Derivative contracts and unamortized contract values	48,351,596	45,186,081
4	State carryforwards	82,972,793	76,749,053
5	Asset retirement obligations	49,995,035	53,101,152
6	Regulatory liabilities	517,326,439	503,204,846
7	Other	53,610,193	54,723,740
8	TOTAL Electric (Enter Total of lines 2 thru 7)	836,588,163	824,459,612
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)	836,588,163	824,459,612

Notes

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201, Common stock issued	750,000,000		
2	TOTAL COMMON STOCK	750,000,000		
3				
4	Account 204, Preferred stock issued			
5	5% Cumulative Preferred	126,533	100.00	
6	Serial Preferred, Cumulative:	3,500,000		
7	6.00% Series		100.00	
8	7.00% Series		100.00	
9	No Par Serial Preferred	16,000,000		
10	TOTAL PREFERRED STOCK	19,626,533		
11				
12	Authorized and Unissued Capital Stock			
13				
14				
15				
16				
17				
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CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT AS REACQUIRED STOCK (Account 217)		HELD BY RESPONDENT IN SINKING AND OTHER FUNDS		Line No.
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
357,060,915	3,417,945,896					1
357,060,915	3,417,945,896					2
						3
						4
						5
						6
5,930	593,000					7
18,046	1,804,600					8
						9
23,976	2,397,600					10
						11
						12
						13
						14
						15
						16
						17
						18
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Schedule Page: 250 Line No.: 1 Column: a

Berkshire Hathaway Energy Company indirectly owns all of the shares of PacifiCorp's outstanding common stock. Therefore, there is no public market for PacifiCorp's common stock.

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

This class of stock is not redeemable.

Schedule Page: 250 Line No.: 7 Column: d

This series of preferred stock is not redeemable.

Schedule Page: 250 Line No.: 8 Column: d

This series of preferred stock is not redeemable.

Schedule Page: 250 Line No.: 12 Column: a

Authorizations for the issuance of common stock are as follows:

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

- 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.

As of December 31, 2017, 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 2018/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		
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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, 2018.

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 2018/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		
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11		
12		
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21		
22	TOTAL	41,101,061

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 2018/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	Account 221, Bonds		
2	First Mortgage Bonds:		
3	5.65% Series due July 15, 2018	500,000,000	3,067,221
4			905,000 D
5	5.50% Series due January 15, 2019	350,000,000	2,515,793
6			2,292,500 D
7	3.85% Series due June 15, 2021	400,000,000	3,007,139
8			744,000 D
9	2.95% Series due February 1, 2022	350,000,000	2,424,350
10			308,000 D
11	2.95% Series due February 1, 2022	100,000,000	254,129
12			-81,000 P
13	2.95% Series due June 1, 2023	300,000,000	1,859,352
14			900,000 D
15	3.60% Series due April 1, 2024	425,000,000	3,345,164
16			255,000 D
17	3.35% Series due July 1, 2025	250,000,000	2,121,421
18			320,000 D
19	7.70% Series due November 15, 2031	300,000,000	2,874,150
20			864,000 D
21	5.90% Series due August 15, 2034	200,000,000	1,892,365
22			722,000 D
23	5.25% Series due June 15, 2035	300,000,000	2,912,021
24			1,080,000 D
25	6.10% Series due August 1, 2036	350,000,000	2,907,881
26			1,141,000 D
27	5.75% Series due April 1, 2037	600,000,000	589,216
28			24,000 D
29	6.25% Series due October 15, 2037	600,000,000	5,127,281
30			750,000 D
31	6.35% Series due July 15, 2038	300,000,000	2,290,333
32			1,671,000 D
33	TOTAL	7,641,475,000	82,117,663

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
07/17/2008	07/15/2018	07/17/2008	07/15/2018		15,302,083	3
						4
01/08/2009	01/15/2019	01/08/2009	01/15/2019	350,000,000	19,250,000	5
						6
05/12/2011	06/15/2021	05/12/2011	06/15/2021	400,000,000	15,400,000	7
						8
01/06/2012	02/01/2022	01/06/2012	02/01/2022	350,000,000	10,325,000	9
						10
03/06/2012	02/01/2022	03/06/2012	02/01/2022	100,000,000	2,950,000	11
						12
06/06/2013	06/01/2023	06/06/2013	06/01/2023	300,000,000	8,850,000	13
						14
03/13/2014	04/01/2024	03/13/2014	04/01/2024	425,000,000	15,300,000	15
						16
06/19/2015	07/01/2025	06/19/2015	07/01/2025	250,000,000	8,375,000	17
						18
11/21/2001	11/15/2031	11/21/2001	11/15/2031	300,000,000	23,100,000	19
						20
08/24/2004	08/15/2034	08/24/2004	08/15/2034	200,000,000	11,800,000	21
						22
06/13/2005	06/15/2035	06/13/2005	06/15/2035	300,000,000	15,750,000	23
						24
08/10/2006	08/01/2036	08/10/2006	08/01/2036	350,000,000	21,350,000	25
						26
03/14/2007	04/01/2037	03/14/2007	04/01/2037	600,000,000	34,500,000	27
						28
10/03/2007	10/15/2037	10/03/2007	10/15/2037	600,000,000	37,500,000	29
						30
07/17/2008	07/15/2038	07/17/2008	07/15/2038	300,000,000	19,050,000	31
						32
				7,055,275,000	358,695,455	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 2018/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	6.00% Series due January 15, 2039	650,000,000	6,134,687
2			6,175,000 D
3	4.10% Series due February 1, 2042	300,000,000	2,737,911
4			987,000 D
5	4.125% Series due January 15, 2049	600,000,000	5,640,085
6			1,344,000 D
7	8.53% Series C Medium-Term Notes due December 16, 2021	15,000,000	115,202
8	8.375% Series C Medium-Term Notes due December 31, 2021	5,000,000	38,400
9	8.26% Series C Medium-Term Notes due January 7, 2022	5,000,000	33,243
10	8.27% Series C Medium-Term Notes due January 10, 2022	4,000,000	30,594
11	8.05% Series E Medium-Term Notes due September 1, 2022	15,000,000	131,471
12	8.07% Series E Medium-Term Notes due September 9, 2022	8,000,000	70,118
13	8.12% Series E Medium-Term Notes due September 9, 2022	50,000,000	438,238
14	8.11% Series E Medium-Term Notes due September 9, 2022	12,000,000	105,177
15	8.05% Series E Medium-Term Notes due September 14, 2022	10,000,000	87,648
16	8.08% Series E Medium-Term Notes due October 14, 2022	26,000,000	208,198
17	8.08% Series E Medium-Term Notes due October 14, 2022	25,000,000	200,190
18	8.23% Series E Medium-Term Notes due January 20, 2023	5,000,000	37,914
19	8.23% Series E Medium-Term Notes due January 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 August 16, 2023	15,000,000	137,211
24	7.24% Series F Medium-Term Notes due August 16, 2023	30,000,000	274,423
25	6.75% Series F Medium-Term Notes due September 14, 2023	5,000,000	38,250
26	6.75% Series F Medium-Term Notes due September 14, 2023	2,000,000	15,300
27	6.72% Series F Medium-Term Notes due September 14, 2023	2,000,000	15,300
28	6.75% Series F Medium-Term Notes due October 26, 2023	20,000,000	152,326
29	6.75% Series F Medium-Term Notes due October 26, 2023	16,000,000	121,861
30	6.75% Series F Medium-Term Notes due October 26, 2023	12,000,000	91,396
31	6.71% Series G Medium-Term Notes due January 15, 2026	100,000,000	904,467
32	Subtotal - First Mortgage Bonds	7,299,000,000	75,645,300
33	TOTAL	7,641,475,000	82,117,663

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
01/08/2009	01/15/2039	01/08/2009	01/15/2039	650,000,000	39,000,000	1
						2
01/06/2012	02/01/2042	01/06/2012	02/01/2042	300,000,000	12,300,000	3
						4
07/13/2018	01/15/2049	07/13/2018	01/15/2049	600,000,000	11,550,000	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
				6,799,000,000	353,219,133	32
				7,055,275,000	358,695,455	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 2018/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	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, Lincoln County, WY, Series 1994	15,060,000	422,858
6	Environ. Imprvmnt Rev Bonds, Converse County, WY, Series 1995	5,300,000	132,043
7	Environ. Imprvmnt Rev Bonds, Lincoln County, WY, Series 1995	22,000,000	404,262
8	Subtotal Pollution Control Obligations - Secured by Pledged First Mortgage Bonds	193,750,000	4,953,665
9			
10	Pollution Control Obligations - Unsecured:		
11	Poll Ctrl Rev Refndng Bonds, City of Forsyth, MT, Series 1988	45,000,000	380,198
12	Poll Ctrl Rev Refndng Bonds, City of Gillette, WY, Series 1988	41,200,000	351,905
13	Poll Ctrl Rev Refndng Bonds, Sweetwater County, WY, Series 1992A	9,335,000	167,524
14	Poll Ctrl Rev Refndng Bonds, Converse County, WY, Series 1992	22,485,000	242,163
15	Poll Ctrl Rev Refndng Bonds, Sweetwater County, WY, Series 1992B	6,305,000	151,908
16	Environ. Imprvmnt Rev Bonds, Sweetwater County, WY, Series 1995	24,400,000	225,000
17	Subtotal - Pollution Control Obligations - Unsecured	148,725,000	1,518,698
18			
19	TOTAL ACCOUNT 221	7,641,475,000	82,117,663
20			
21	Account 222, Reacquired bonds		
22			
23	Account 223, Advances from associated companies		
24			
25	Account 224, Other long-term debt		
26			
27	Long-Term Debt Authorized but Unissued		
28			
29			
30			
31			
32			
33	TOTAL	7,641,475,000	82,117,663

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	496,056	2
11/17/1994	11/01/2024	11/17/1994	11/01/2024	8,190,000	151,585	3
11/17/1994	11/01/2024	11/17/1994	11/01/2024	121,940,000	2,744,533	4
11/17/1994	11/01/2024	11/17/1994	11/01/2024	15,060,000	294,273	5
11/17/1995	11/01/2025	11/17/1995	11/01/2025	5,300,000	95,772	6
11/17/1995	11/01/2025	11/17/1995	11/01/2025	22,000,000	426,101	7
				193,750,000	4,208,320	8
						9
						10
01/01/1988	01/01/2018	01/01/1988	01/01/2018			11
01/01/1988	01/01/2018	01/01/1988	01/01/2018			12
09/29/1992	12/01/2020	09/29/1992	12/01/2020	9,335,000	174,425	13
09/29/1992	12/01/2020	09/29/1992	12/01/2020	22,485,000	418,974	14
09/29/1992	12/01/2020	09/29/1992	12/01/2020	6,305,000	118,019	15
12/14/1995	11/01/2025	12/14/1995	11/01/2025	24,400,000	556,584	16
				62,525,000	1,268,002	17
						18
				7,055,275,000	358,695,455	19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				7,055,275,000	358,695,455	33

Schedule Page: 256.1 Line No.: 5 Column: a

In July 2018, PacifiCorp issued $600 million of its 4.125% First Mortgage Bonds due January 2049. State commission authorizations for this issuance were as follows:

- Idaho Public Utilities Commission ("IPUC") – Case No. PAC-E-14-05, Order No. 33083, dated July 29, 2014, effective through June 30, 2019.
- Oregon Public Utility Commission ("OPUC") - Docket No. UF-4288, Order No. 14-268, dated July 22, 2014.

Schedule Page: 256.2 Line No.: 19 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.: 19 Column: i

Account 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.: 27 Column: a

For authorization for the issuance of long-term debt ($2.0 billion authorized; $2.0 billion available as of December 31, 2018), 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, 2018) 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, 2018) 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 2018/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)	737,709,000
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8	Other	207,262,370
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13	Other	1,161,583,337
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18	Other	30,289,898
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25	Other	973,987,622
26	State Tax Deductions	-74,644,722
27	Federal Tax Net Income	1,027,632,465
28	Show Computation of Tax:	
29		
30	Federal Income Tax at 21.00%	215,802,818
31	Provision to Return Adjustment	-7,135,278
32	Tax Reserve Changes	3,653,988
33	Research and Experimentation Credits	-32,500
34	Renewable Energy Production Tax Credits	-48,824,841
35		
36	Federal Income Tax Accrual	163,464,187
37		
38		
39		
40		
41		
42		
43		
44		

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

Particulars (Details)	Amounts
Contribution in Aid of Construction	$ 107,657,673
Investment Gain/Loss - Book - Current	1,260
MCI F.O.G. Wire Lease	612
Regulatory Asset - Alt Rate for Energy Program (CARE) - CA	242,877
Regulatory Asset - REC Sales Deferral - OR	186,144
Regulatory Asset - WA Colstrip #3	52,188
Regulatory Liability - Deferred Excess NPC - OR	5,658,668
Regulatory Liability - Deferred Excess NPC - WA	4,646,412
Regulatory Liability - Depreciation Decrease - OR	1,209,098
Regulatory Liability - Excess Income Tax Deferral - ID	555,684
Regulatory Liability - Excess Income Tax Deferral - OR	48,555,250
Regulatory Liability - Excess Income Tax Deferral - UT	527,997
Regulatory Liability - Excess Income Tax Deferral - WA	8,502,721
Regulatory Liability - Excess Income Tax Deferral - WY	7,002,187
Regulatory Liability - Excess Income Tax Deferral - CA	3,199,939
Regulatory Liability - GHG Allowance Revenues - CA	1,036,410
Regulatory Liability - OR Direct Access 5 Year Opt Out	1,690,477
Regulatory Liability - WA Accel Depreciation	12,611,581
Reimbursements	2,098,861
Transmission Service Deposits	1,826,331
Total	$ 207,262,370

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

Particulars (Details)	Amounts
Fed/State Tax Expense	$ 3,035,123
Fed/State Tax Expense - Interest	(2,310,077)
Meals and Entertainment	1,056,316
Accrued Retention	343,425
Accrued Royalties	1,719,906
Accrued Severance	18,322
Accrued Vacation	236,928
Avoided Costs	29,861,966
Bear River Settlement Agreement	1,825
Book Depreciation	967,774,681
Book Depreciation Allocated to Medicare and M&E	92,436
Capitalized Labor and Benefit Costs	4,907,150
Coal Pile Inventory Adjustment	328,692
Company Plane - Nonbusiness Use	9,353
CWIP Reserve	1,280,812
Deferred Compensation Mark to Market Gain/Loss - Income Statement	1,024,390
Deferred Revenue - Citibank	281,105
Deferred Revenue - Other	992,169
Environmental Liability - Regulated	3,202,927
Hermiston Swap	171,693
Hydro Relicensing Obligation	1,329,337
Injuries and Damages Accrual - Cash Basis	7,222,357
Injuries & Damages Reserve - OR	494,665
Insurance Reserve	2,572,184
Inventory Reserve	12,239
Joseph Settlement	11,447
Lewis River Settlement Agreement	21,845
Lobbying Expenses	1,246,332
LT Incentive Plan	4,640,301
LT Incentive Plan Mark to Market Gain/Loss	1,156,059
Medicare Subsidy	7,089,521
Non-deductible Fringe Benefits	472,628
Non-deductible Legal Fees	300,000
Non-deductible Parking Costs	150,834
Penalties	1,053,701
Prepaid Aircraft Maintenance	60,994
Prepaid Membership Fees	3,879,868
Prepaid Taxes - IPUC	11,555
Prepaid Taxes - UPSC	5,122
Prepaid Water Rights	31,250
Property Insurance Reserve - ID	113,544
Property Insurance Reserve - OR	3,634,154
Property Insurance Reserve - UT	2,033,447
Property Insurance Reserve - WY	349,810

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 - Demand Side Management	19,966,390
Regulatory Asset - Depreciation Increase - ID	4,220,182
Regulatory Asset - Depreciation Increase - UT	128,043
Regulatory Asset - Depreciation Increase - WY	442,191
Regulatory Asset - Environmental Costs - WA	48,290
Regulatory Asset - FAS 158 Pension Liability	37,508,593
Regulatory Asset - Klamath Hydroelectric Relicensing Costs - UT	3,569,658
Regulatory Asset - Liquidated Damages - UT	35,000
Regulatory Asset - Liquidated Damages - WY	54,288
Regulatory Asset - Pension MMT - UT	1
Regulatory Asset - Postemployment Costs	476,510
Regulatory Asset - Post Merger Loss - Reacquired Debt	584,922
Regulatory Asset - Postretirement MMT - CA	17,487
Regulatory Asset - Postretirement MMT - OR	193,034
Regulatory Asset - Postretirement MMT - UT	1
Regulatory Asset - Postretirement Settlement Loss	353,077
Regulatory Asset - Postretirement Settlement Loss CC - WY	22,244
Regulatory Asset - Powerdale Decommissioning - ID	25,986
Regulatory Asset - Preferred Stock Redemption Loss - UT	82,529
Regulatory Asset - Preferred Stock Redemption Loss - WA	13,318
Regulatory Asset - Preferred Stock Redemption Loss - WY	28,442
Regulatory Asset - Solar Feed-In Tariff Deferral - OR	203,337
Regulatory Asset - Transportation Electrification Program - CA	457,600
Regulatory Asset - STEP Pilot Program Balance Account - UT	4,246,567
Regulatory Asset - Utah Mine Disposition	18,036,990
Regulatory Liability - 50% Bonus Tax Depreciation - WY	604,331
Regulatory Liability - ARO/Reg Diff - Trojan - WA Portion	2,936
Regulatory Liability - Blue Sky - OR	425,292
Regulatory Liability - Blue Sky - ID	45,363
Regulatory Liability - Blue Sky - UT	1,469,548
Regulatory Liability - Blue Sky - WA	114,994
Regulatory Liability - Blue Sky - WY	34,231
Regulatory Liability - Clean Fuels Program - OR	487,500
Regulatory Liability - Contra-Carbon Decommissioning - WY	535,226
Regulatory Liability - OR Energy Conservation Charge	603,255
Regulatory Liability - Solar Incentive Program - UT	4,105,884
Regulatory Liability - WA Decoupling Mechanism	2,067,109
TGS Buyout	15,473
Trapper Mine Contract Obligation	258,310
Intercompany Adjustment	3,095,401
Total	$1,161,583,337

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

Particulars (Details)	Amounts
Book Fixed Asset Gain/Loss	$ (955,309)
Deferred Revenue - Lease Incentives	(538,993)
Dividend Received Deduction - Deferred Compensation	(194,310)
Investment Gain/Loss - Tax	(2,313)
Officer's Life Insurance	(2,962,869)
Regulatory Asset - BPA Balancing Account - OR	(982,639)
Regulatory Asset - REC Sales Deferral - UT	(955,066)
Regulatory Asset - REC Sales Deferral - WA	(14,843)
Regulatory Asset - REC Sales Deferral - WY	(317,086)
Regulatory Liability - BPA Balancing Account - ID	(220,266)
Regulatory Liability - BPA Balancing Account - WA	(173,130)
Regulatory Liability - UT Home Energy Lifeline	(67,859)
Regulatory Liability - WA Low Income Program	(874,054)
Trapper Mining Stock Basis	(1,113,723)
Unearned Joint Use Pole Contract Revenue	(47,460)
Equity Earnings in Subsidiaries	(20,869,978)
Total	$ (30,289,898)

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

Particulars (Details)	Amounts
Accrued Bonus	$ (80,070)
Accrued Final Reclamation	(240,352)
Amortization NOPAs 99-00 RAR	(48,816)
Basis Intangible Difference	(194,947)
Capitalized Depreciation	(5,977,157)
Cholla SHL NOPA (Lease Amortization)	(318,535)
Contra Receivable from Joint Owners	(103,734)
Cost of Removal	(40,800,230)
Debt AFUDC	(18,379,196)
Deferred Compensation	(802,480)
Deseret Settlement Receivable	(126,298)
Environmental Liability - Non-regulated	(19,631)
Equity AFUDC - Temp	(34,708,432)
FAS 112 Book Reserve - Postemployment Benefits	(1,373,022)
FAS 158 Pension Liability	(31,277,812)
FAS 158 Postretirement Liability	(8,352,010)
FAS 158 SERP Liability	(1,418,659)
Federal Tax Depreciation	(562,859,697)
Federal Tax Fixed Asset Gain/Loss	(9,887,461)
Fuel Cost Adjustment	(2,845,931)
Income Tax Interest	(1,513,017)
Miscellaneous Current and Accrued Liability	(959,491)
N Umpqua Settlement Agreement	(584,971)
Non-deductible Postretirement Costs	(7,089,521)
Oregon Regulatory Asset/Regulatory Liability Consolidation	(192)
Pension/Retirement Accrual	(155,077)
Pre-1943 Preferred Stock Dividend - Deduction	(107,935)
Prepaid Taxes - OPUC	(41,920)
Prepaid Taxes - Property Taxes	(197,416)
Regulatory Asset - Asset Sales Balancing Account - OR	(761,496)
Regulatory Asset - CA Mobile Home Park Conversion	(124,888)
Regulatory Asset - Catastrophic Event Deferral - CA	(2,179,411)
Regulatory Asset - Contra Pension MMT & CTG - CA	(90,033)
Regulatory Asset - Contra Pension MMT & CTG - OR	(1,007,506)
Regulatory Asset - Contra Regulatory Asset - Pension Plan CTG	(1,640,983)
Regulatory Asset - Deferred Excess NPC - CA	(2,506,056)
Regulatory Asset - Deferred Excess NPC - ID	(8,692,289)
Regulatory Asset - Deferred Excess NPC - UT	(22,812,564)
Regulatory Asset - Deferred Excess NPC - WY '09 & After	(5,512,772)
Regulatory Asset - Deferred Independent Evaluator Fee - UT	(139,555)
Regulatory Asset - Deferred Intervenor Funding Grants - CA	(976)
Regulatory Asset - Deferred Intervenor Funding Grants - ID	(40,000)
Regulatory Asset - Deferred Intervenor Funding Grants - OR	(391,443)
Regulatory Asset - Deferred Overburden Costs - ID	(139,271)
Regulatory Asset - Deferred Overburden Costs - WY	(391,879)
Regulatory Asset - Environmental Costs	(3,821,579)
Regulatory Asset - FAS 158 Postretirement Liability	(6,145,999)
Regulatory Asset - OR Transportation Electrification Program	(48,792)
Regulatory Asset - Protocol - MSP Deferral - ID	(150,000)
Regulatory Asset - Protocol - MSP Deferral - UT	(4,400,000)
Regulatory Asset - Protocol - MSP Deferral - WY	(1,600,000)
Regulatory Asset - Solar Incentive Program - UT	(4,246,567)
Regulatory Asset - UT Subscriber Solar Program	(112,324)
Regulatory Asset - Postretirement Settlement Loss CC - UT	(291,300)
Regulatory Liability - Blue Sky - CA	(65,538)
Regulatory Liability - Deferred Excess NPC - UT	(3,999,381)
Regulatory Liability - Deferred Excess NPC - WY	(7,899,057)
Regulatory Liability - Energy Savings Assistance - CA	(111,582)
Regulatory Liability - Solar Feed-in Tariff Deferral - CA	(464,195)
Repairs Deduction	(161,179,370)
Reserve for Bad Debts	(2,117,994)
Rogue River - Habitat Enhancement Liability	(73,640)
Tax Depletion - SRC	(32,453)
Trojan Decommissioning	(36,774)
Wasatch Workers Compensation Reserve	(193,945)
Western Coal Carrier Retiree Medical Accrual	(102,000)
Total	$ (973,987,622)

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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
Alamo 6, LLC
Alaska Gas Transmission Company, LLC
Allie Beth Allman Real Estate, Ltd
Ambassador Real Estate Company
Ambassador Real Estate-Lincoln, LLC
Apex Home Maintenance, LLC
ARE Commercial Real Estate, LLC
ARE Iowa, LLC
Arizona HomeServices, LLC
Attorneys Title Holdings, Incorporated
Berkshire Hathaway Energy Company
BG Energy Holding Company LLC
BH2H Holdings, LLC
BHE AC Holding, LLC
BHE America Transco, LLC
BHE Canada LLC
BHE Community Solar, LLC
BHE Gas, Inc.
BHE Geothermal, LLC
BHE Hydro, LLC
BHE Midcontinent Transmission Holdings LLC
BHE Pearl Solar Holdings, LLC
BHE Pearl Solar, 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
BHER Power Resources, Inc.
BHER Santa Rita Holdings, LLC
BHER Santa Rita Investment, LLC
BHER Santa Rita Tax, Inc.
BHES CSG Holdings, LLC
BHES Pearl Solar Holdings, LLC
BHH KC Real Estate, LLC
Big Spring Pipeline Company
Bishop Hill Energy II, LLC
Bishop Hill II Holdings, LLC
CalEnergy Company, Inc.
CalEnergy Generation Operating Company
CalEnergy International Services, Inc.
CalEnergy Minerals LLC
CalEnergy Operating Corporation
CalEnergy Pacific Holdings Corp
California Energy Development Corporation
California Energy Management Company
California Energy Yuma Corporation
California Utility Holdco, LLC
Capitol Title Company
CBSHome Real Estate Company
CBSHome Real Estate of Iowa, 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.
Columbia Title of Florida, Inc.
Commonsite, Inc.
Conejo Energy Company
Cordova Energy Company, LLC
CTHM, L.L.C.
CTRE, L.L.C.
Dakota Dunes Development Company
DCCO, Inc.
Del Ranch Company
Denver Rental, LLC
Desert Valley Company
DG-SB Project Holdings, LLC
Ebby Alumni Group, Inc.
Ebby Halliday Properties, Inc.
Ebby Halliday Real Estate, Inc.
Edina Financial Services, Inc.
Edina Realty Insurance, LLC
Edina Realty Referral Network, Inc.
Edina Realty Title, Inc.
Edina Realty, Inc.
Elmore Company
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.
Fort Dearborn Land Title Company, LLC
FRTC, LLC
Geronimo Community Solar Gardens Holding Company, LLC
Geronimo Community Solar Gardens, LLC
Gibraltar Title Services, LLC
GPWH Holdings, LLC
Grande Prairie Land Holding, LLC
Grande Prairie Wind Holdings, LLC
Grande Prairie Wind II, LLC
Grande Prairie Wind, LLC
Greystone Partners of Virginia, 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
Home Service Connections, LLC
HomeServices Insurance Agency, LLC
HomeServices Insurance, Inc.
HomeServices Lending, LLC
HomeServices MidAtlantic, LLC
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 Illinois, LLC
HomeServices of Iowa, Inc.
HomeServices of Kentucky Real Estate Academy, LLC
HomeServices of Kentucky, Inc.
HomeServices of Minnesota, LLC
HomeServices of MOKAN, LLC
HomeServices of Nebraska, Inc.
HomeServices of New Jersey, LLC
HomeServices of New York, LLC
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
Houlihan/Lawrence Inc.
HS Franchise Holding, LLC
HSF Affiliates LLC
HSGA Real Estate Group, L.L.C.
HSN Holding, LLC
HSTX Title, LLC
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
JBRC, Inc.
Jim Huff Realty, Inc.
JRHBW Realty, Inc. d/b/a RealtySouth
Jumbo Road Holdings, LLC
Kansas City Title, Inc.
Kanstar Transmission, LLC
Kentucky Residential Referral Service, LLC
Kentwood City Properties, LLC
Kentwood Commercial, LLC
Kentwood DTC, LLC
Kentwood Real Estate Services, LLC
Kentwood, LLC
Kern River Gas Transmission Company
Keystone Partners, LLC
KR Holding, LLC
L&F/Fonville Morisey Real Estate, LLC
L&F/Fonville Morisey Title, LLC
Lands of Sierra, Inc.
Larabee School of Real Estate, Inc.
LFFS, Inc.
Long & Foster Closing Services, LLC
Long & Foster Institute of Real Estate, Inc.
Long & Foster Insurance Agency, Inc.
Long & Foster Licensing Company, Inc.
Long & Foster Mortgage Ventures, Inc.
Long & Foster Real Estate Ventures, Inc.
Long & Foster Real Estate, Inc.
Long & Foster Settlement Services, LLC
Lovejoy Realty Inc.
Lovejoy Referral Network, LLC
M & M Ranch Acquisition Company LLC
M & M Ranch Holding Company LLC
Magma Land Company I
Magma Power Company
Marshall Wind Energy Holdings, LLC
Marshall Wind Energy, LLC
MEC Construction Services Company
MEHC Investment, Inc.
MEHC Merger Sub Inc.
Merlin Realty Technologies, LLC
MES Holding, LLC
Metro Referral Associates, Inc.
MHC Investment Company
MHC, Inc.
Mid-America Referral Network, Inc.
MidAmerican Central California Transco LLC
MidAmerican Energy Company
MidAmerican Energy Machining Services LLC
MidAmerican Energy Services, LLC
MidAmerican Funding, LLC
MidAmerican Geothermal Development Corp
MidAmerican Wind Tax Equity Holdings, LLC
Midland Escrow Services, Inc.
Mid-States Title Insurance Agency, Inc.
Midwest Capital Group, Inc.
Midwest Power Midcontinent Transmission Development, LLC
Midwest Power Transmission Arkansas LLC
Midwest Power Transmission Iowa LLC
Midwest Power Transmission Kansas, LLC
Midwest Power Transmission Oklahoma, LLC
Midwest Power Transmission Texas, LLC
Midwest Preferred Realty, Inc.
Midwest Realty Ventures, LLC
MPT Heartland Development, LLC
MTL Canyon Holdings LLC
Nebraska Land Title & Abstract Company
Nebraska Referral, Inc.

Nevada Power Company d/b/a NV Energy Inc.
Niguel Energy Company
NNGC Acquisition LLC
Norcon Holdings, Inc.
Northeast Referral Group, LLC
Northern Consolidated Power, Inc.
Northern Natural Gas Company
NRS Referral Services, LLC
NV Energy, Inc.
NVE Holdings, LLC
NVE Insurance Co, Inc.
NW Referral Services, LLC
O.E. Merger Sub II, LLC
O.E. Merger Sub III, LLC
O.E. Merger Sub Inc.
PCG Agencies, Inc.
PCRE, L.L.C.
Pickford Escrow Company, Inc.
Pickford Holdings, LLC
Pickford Real Estate, Inc.
Pickford Services Company, Inc.
Pilot Butte, LLC
Pinyon Pines Funding, LLC
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
Preferred Carolinas Realty, Inc.
Preferred Carolinas Title Agency, LLC
Premier Service Abstract, LLC
Priority Title Corporation
Professional Referral Organization, Inc.
Pru-One, Inc.
Quad Cities Energy Company
Real Estate Knowledge Services, L.L.C.
Real Estate Links, LLC
Real Estate Referral Network, Inc.
Reece & Nichols Alliance, Inc.
Reece & Nichols Insurance, LLC
Reece & Nichols Realtors, Inc.
Reece Commercial, Inc.
Referral Associates of Georgia, LLC
Referral Network of Gloria Nilson, LLC
Referral Network of IL LLC
Referral Network of NY/NJ, LLC
Relocation Advantage Partners, LLC
RGS Settlements of Pennsylvania, LLC
RGS Title of Baltimore, LLC
RGS Title, LLC
RHL Referral Company, LLC
Roberts Brothers, Inc.
Roy H. Long Realty Company, Inc.
S.W. Hydro, Inc.
Sage Title Group, LLC
Salton Sea Brine Processing Company
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
Santa Rita Wind Energy LLC
Saranac Energy Company, Inc.
SCS Realty Investment Group, LLC
SECI Holdings, Inc.
Settlement Professionals, LLC
Sierra Gas Holding Company
Sierra Pacific Power Company d/b/a NV Energy Inc.
Silvermine Ventures LLC
Solar San Antonio LLC
Solar Star 3, LLC
Solar Star 4, 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 Long & Foster Companies, Inc.
The Referral Company
Thoroughbred Title Services, LLC
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.
Walker Jackson Mortgage Corporation
Walnut Ridge Wind, LLC
Weathervane Referral Network, Inc.

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
21 SPC, Inc.
21st Communities, Inc.
21st Mortgage Corporation
2K Polymer Systems, Inc.
3Wire Group Inc.
A.E. Company, Inc.
AAA Aircraft Supply
Accra Manufacturing Inc.
Accurate Installations, Inc.
Acme Brick Company
Acme Building Brands, Inc.
Acme Management Company
Acme Ochs Brick and Stone, Inc.
Acme Services Company, LLC
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.
Albacor Shipping (USA) Inc.
Albecca, Inc.
Alexander Road Insurance Agency, Inc.
Alpha Cargo Motor Express, Inc.

Alu-Forge, Inc.
Ambucor Health Solutions, 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
Angelo Po America, Inc.
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 Co., Inc.
Applied Underwriters, Inc.
Arcturus Manufacturing Corporation
Artform International Inc.
Atlanta International Insurance Company
Atlantic Precision, Inc.
AU Captive Risk Assurance Co.
AU Holding Company, Inc.
Avibank Manufacturing Inc.
AzGUARD Insurance Company
Bayport Systems, Inc.
BDT I-A Plum Corp.
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 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 Holding LLC
BH Media Group, Inc.
BH Shoe Holdings, Inc.
BHA Minority Interest Holdco, Inc.
BHG Life Insurance Company
BHG Structured Settlements, Inc.
BHSF, Inc.
biBERK Insurance Services, Inc.
Blue Chip Stamps, Inc.
BN Leasing Corporation
BNSF Communications, Inc.
BNSF Logistics International, Inc.
BNSF Logistics Ocean Line, Inc.
BNSF Logistics, LLC
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.
Borsheim Jewelry Company, Inc.
BR Agency, Inc.
Brainy Toys, Inc.
Brilliant National Services, Inc.
Brittain Machine Inc.
Brooks Sports, Inc.
Brookwood Insurance Company
BuilderMT, Inc.
Burlington Northern Railroad Holdings, Inc.
Burlington Northern Santa Fe, LLC
Business Wire, Inc.
C Flow, Inc.
Caledonian Alloys Inc.
California Insurance Company
Camp Manufacturing 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.
Chemtool Incorporated
CJE II
Claims Services, Inc.
Clayton Commercial Buildings, Inc.
Clayton Education Corp.
Clayton Homes, Inc.
Clayton Properties Group II, Inc.
Clayton Properties Group, Inc.
Clayton, Inc.
CMH Capital, Inc.
CMH Hodgenville, Inc.
CMH Homes, Inc.
CMH Manufacturing West, Inc.
CMH Manufacturing, Inc.
CMH of KY, Inc.
CMH Services, Inc.
CMH Set and Finish, Inc.
CMH Transport, Inc.
Coil Master Corporation
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
Consumer Value Products, Inc.
Continental Divide Insurance Company
Continental Indemnity Company
Cornelius Inc.
Cornelius Renew, Inc.
Cort Business Services Corporation
Coverage Dynamics Group, Inc.
Criterion Insurance Agency
Crowd Supply, Inc.
CSI Life Insurance Company
CTB Credit Corp
CTB Inc.
CTB International Corp
CTB IW Inc.
CTB Midwest Inc.
CTB MN Investments
CTB Technology Holding Inc.
CTMS North America, Inc.
Cubic Designs, Inc.
Cumberland Asset Management, Inc.
Cypress Insurance Company
D.I. Properties Inc.
Dairy Queen Corporate Stores, Inc.
DaVita, Inc.
DCI Marketing Inc.
Denver Brick Company
Designed Metal Connections, Inc.
Dickson Testing Co., Inc.

Display Technologies LLC
DIY Technologies, Inc.
DL Trading Holdings I, Inc.
DQ Funding Corporation
DQF, Inc.
DQGC, Inc.
DragonFly Aeronautics LLC
DTTF, Inc.
Duracell Distributing Inc.
Duracell Industrial Operations, Inc.
Duracell Manufacturing Co.
Duracell U.S. Operations Inc.
EastGUARD Insurance Company
Eco Color Company
Ecodyne Corporation
Ellis & Watts Global Industries, Inc.
Elm Street Corporation
Empire Distributors of Colorado, Inc.
Empire Distributors of North Carolina, Inc.
Empire Distributors of Tennessee, Inc.
Empire Distributors, Inc.
Environment One Corporation
Exacta Aerospace Inc.
Executive Jet Management, Inc.
Exsif Worldwide, Inc.
ExtruMed, Inc.
Fatigue Technology Inc.
Financial Services Plus, Inc.
Finial Holdings, Inc.
Finial Reinsurance Company
First Berkshire Hathaway Life Insurance Company
FlightSafety Capital Corp.
FlightSafety Development Corp.
FlightSafety International Inc.
FlightSafety International Middle East Inc.
FlightSafety New York, Inc.
FlightSafety Properties, Inc.
FlightSafety Services Corporation
Floors, Inc.
Focused Technology Solutions, Inc.
Fontaine Commercial Trailer, Inc.
Fontaine Engineered Products, Inc.
Fontaine Fifth Wheel Company
Fontaine Modification Company
Fontaine Spray Suppression Company
Fontaine Trailer Company LLC
Forest River Holdings, Inc.
Forest River Manufacturing LLC
Forest River, Inc.
Freedom Warehouse Corp.
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 Reinsurance Corporation
General Star Indemnity Company
General Star Management Company
General Star National Insurance Company
Genesis Insurance Company
Genesis Management and Insurance Services Corp.
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
Hamilton Aviation Inc.
Hawthorn Life International, Ltd.
HeatPipe Technology, Inc.
Helicomb International Inc.
Helzberg's Diamond Shops, Inc.
Henley Holdings, LLC
HG-Power Plant, Inc.
Hohmann & Barnard, Inc.
Home Trust Company
Homefirst Agency, Inc.
Homemakers Plaza, Inc.
Howell Penncraft, Inc.
HUM Marketing Group, Inc.
Huntington Alloys Corporation
IdeaLife Insurance Company
Illinois Insurance Company
Ingersoll Cutting Tool Company
Innovative Building Products, Inc.
Innovative Coatings Technology Corporation
Interco Tobacco Retailers, Inc.
International Dairy Queen, Inc.
International Insurance Underwriters, Inc.
Intrepid JSB, Inc.
Ironwood Plastics Inc.
Iscar Metals Inc.
ITTI Group USA Holdings, Inc.
ITTI Investment Holdings, Inc.
J&L Mining Company
J.L. Fiber Services Inc.
Johns Manville China, Ltd.
Johns Manville Corporation
Johns Manville, Inc.
Jordan's Furniture, Inc.
Justin Brands, Inc.
Kahn Ventures, Inc.
Karmelkorn Shoppes, Inc.
Ken's Spray Equipment, Inc.
Kinexo, Inc.
KITCO Fiber Optics, Inc.
Klune Holdings Inc.
Klune Industries Inc.
Kova Solutions, Inc.
L.A. Terminals, Inc.
LeachGarner, Inc.
Lipotec USA, Inc.
LiquidPower Specialty Products, Inc.
LJ Aero Holdings Inc.
LJ Synch Holdings Inc.
LMG Ventures, LLC
Lockwood Street Urban Renewal Corporation
Los Angeles Junction Railway Company
LSP Holding, Inc.
LSPI Holdings Inc.
Lubricant Investments, Inc.

Lubrizol Advanced Materials China, Inc.
Lubrizol Advanced Materials Holding Corporation
Lubrizol Advanced Materials, Inc.
Lubrizol Global Management, Inc.
Lubrizol Inter-Americas Corporation
Lubrizol International Management Corporation
Lubrizol Oilfield Solutions, Inc.
Lubrizol Overseas Trading Corporation
M&C Products, Inc.
M&M Manufacturing, Inc.
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 Retail & Highway Technologies Co. LLC
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.
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 Foods, Inc.
McLane Foodservice Distribution, Inc.
McLane Foodservice, Inc.
McLane Mid-Atlantic, Inc.
McLane Midwest, Inc.
McLane Minnesota, Inc.
McLane Network Solutions, Inc.
McLane New Jersey, Inc.
McLane Ohio, Inc.
McLane Southern, Inc.
McLane Suneast, Inc.
McLane Tri-States, Inc.
McLane Western, Inc.
McWilliams Forge Company
Medical Protective Finance Corporation
MedPro Group, Inc.
MedPro Risk Retention Services, Inc.
Merit Distribution Services, Inc.
Metalac Fasteners Inc.
Meyn LLC
MFS Fleet, Inc.
Midwest Northwest Properties, Inc.
Miller-Sage, Inc.
Mindware Corporation
MiTek Holdings, Inc.
MiTek Industries, Inc.
MiTek USA, Inc.
MLMIC Insurance Company
MLMIC Services, Inc.
Montana Retail Properties, Inc.
Morgantown-National Supply, Inc.
Mount Vernon Fire Insurance Company
Mount Vernon Specialty Insurance Company
Mouser Electronics, Inc.
Mouser JV 1, Inc.
MPP Co., Inc.
MPP Pipeline Corporation
MS Property Company
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 Sales, Inc.
NetJets Services, Inc.
NetJets U.S., Inc.
New England Asset Management, Inc.
NFM of Kansas, Inc.
NFM Services, LLC
NJE Holdings, LLC
NJI Sales, Inc.
Noranco Manufacturing (USA) Ltd.
NorGUARD Insurance Company
North American Casualty Co.
Northern States Agency, Inc.
Noveon Hilton Davis, Inc.
NSS Technologies Inc.
Oak River Insurance Company
Old United Casualty Company
Orange Julius Of America
Oriental Trading Company, Inc.
OTC Brands, Inc.
OTC Direct, Inc.
OTC Worldwide Holdings, Inc.
Particle Sciences, Inc.
PCC Flow Technologies Holdings Inc.
PCC Flow Technologies Inc.
PCC Rollmet Inc.
PCC Structurals Inc.
Penn Coal Land, Inc.
Pennsylvania Insurance Company
Perfection Hy-Test Company
Permaswage Holdings, Inc.
Pine Canyon Land Company
Plasma Coating Corporation
Plaza Financial Services Co.
Plaza Resources Co.
PLICO
PLICO Financial, Inc.
Polysols Holdings, Inc.
Polysols Textile Solutions, Inc.
Precision Brand Products, Inc.
Precision Castparts Corp
Precision Founders Inc.
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.
PRISM Holdings LLC
PRISM Plastics, Inc.
Pro Installations, Inc.
Procrane Holdings, Inc.
Progressive Incorporated
Promesa Health, Inc.
Protective Coating Inc.
QS Partners LLC

R.C. Willey Home Furnishings
Radnor Specialty Insurance Company
Railserve, Inc.
Railsplitter Holdings Corporation
RathGibson Holding Co LLC
RCP Investment, Inc.
Redwood Fire and Casualty Insurance Company
RENTCO Trailer Corporation
Resolute Management Inc.
RFMW, Ltd.
Richline Group, Inc.
Ringwalt & Liesche Co.
Rio Grande, Inc.
Roxell USA, Inc.
Rush Air Inc.
Sager Electrical Supply Co. Inc.
Sales Simplicity Software, Inc.
Santa Fe Pacific Insurance Company
Santa Fe Pacific Pipeline Holdings, Inc.
Santa Fe Pacific Pipelines, Inc.
Santa Fe Pacific Railroad Company
Schill Loans, Inc.
Schulz Investment Corporation
Schulz U.S.A. Inc.
Scott Fetzer Financial Group, Inc.
ScottCare Corporation
See's Candies, Inc.
See's Candy Shops, Incorporated
Serpentec, Inc.
Seventeenth Street Realty, Inc.
SFEG Corp.
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 Sports Turf California, Inc.
Shaw Transport, Inc.
Shultz Steel Company
SHX Flooring, Inc.
SidePlate Systems, Inc.
Smilemakers Canada Inc.
Smilemakers, Inc.
SN Management, Inc.
Snappy ADP, Inc.
Soco West, Inc.
Sonnax Transmission Company
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
SPS Technologies Mexico LLC
SSP-SiMatrix Inc.
Stahl/Scott Fetzer Company
Star Furniture Company
Star Lake Railroad Company
Strategic Staff Management, Inc.
StratoFlight
Summit Distribution Services, Inc.
SXP CRA-OCTG Inc.
TBS USA, Inc.
Texas Honing Inc.
Texas Insurance Company
The Ben Bridge Corporation
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.
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.
Tricycle, Inc.
TSE Brakes, Inc.
TTI, Inc.
Tucker Safety Products, Inc.
TXFM, 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.
United Consumer Financial Services Company
United Direct Finance, Inc.
United States Aviation Underwriters, Inc.
United States Liability Insurance Company
University Swaging Corporation
UTLX Company
Van Enterprises, Inc.
Vanderbilt ABS Corp.
Vanderbilt Mortgage and Finance, Inc.
Vanity Fair, Inc.
Velocity Freight Transport, Inc.
Veritas Insurance Group, Inc.
Vesta Funding, Inc.
Vesta Intermediate Funding, Inc.
VFI-Mexico, Inc.
Visilinx, Inc.
Vision Retailing, 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.
Wrightsoft Corporation
Wyman Gordan Investment Castings Inc.
Wyman Gordon Company
Wyman Gordon Forgings Cleveland Inc.
Wyman Gordon Forgings Inc.
Wyman Gordon Pennsylvania LLC
X-L-Co., Inc.
XTRA Companies, Inc.
XTRA Corporation
XTRA Finance Corporation
XTRA Intermodal, Inc.

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 2018/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Federal:					
2	Income	2,086,346		163,464,187	92,864,797	68,665,825
3	FICA	540,378	6,511	36,918,373	36,908,951	
4	Unemployment	-34,160		233,225	192,630	
5	Foreign Withholding Taxes	1,522,888				
6	Subtotal	4,115,452	6,511	200,615,785	129,966,378	68,665,825
7						
8	State:					
9						
10	Arizona:					
11	Property	1,830,515		2,872,740	3,266,885	
12	Income			507,261	500,351	5,154
13	Subtotal	1,830,515		3,380,001	3,767,236	5,154
14						
15	California:					
16	Property			2,251,937	2,251,937	
17	Unemployment	132		23,753	22,353	
18	Franchise-Income			2,639,526	1,918,210	99,612
19	Use	9,643		356,402	356,000	
20	Local Franchise	1,311,455		1,353,368	1,290,959	
21	Subtotal	1,321,230		6,624,986	5,839,459	99,612
22						
23	Colorado:					
24	Property	2,330,000		2,930,427	2,410,427	
25	Subtotal	2,330,000		2,930,427	2,410,427	
26						
27	Idaho:					
28	Property	3,651,782		6,415,434	6,369,005	
29	Income			2,447,140	2,188,279	189,268
30	KWh	18,336		77,507	78,673	
31	Unemployment	2,447		63,998	64,888	
32	Use	5,819		271,022	240,368	
33	Subtotal	3,678,384		9,275,101	8,941,213	189,268
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	46,331,988	13,392,342	456,348,060	382,773,438	71,805,641

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 2018/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
4,019,911		162,384,813			1,079,374	2
543,289					36,918,373	3
6,435					233,225	4
1,522,888						5
6,092,523		162,384,813			38,230,972	6
						7
						8
						9
						10
1,436,370		2,872,740				11
1,756		504,449			2,812	12
1,438,126		3,377,189			2,812	13
						14
						15
		2,115,104			136,833	16
1,532					23,753	17
621,704		2,626,470			13,056	18
10,045					356,402	19
1,373,864		1,353,368				20
2,007,145		6,094,942			530,044	21
						22
						23
2,850,000		2,928,875			1,552	24
2,850,000		2,928,875			1,552	25
						26
						27
3,698,211		6,414,355			1,079	28
69,593		2,431,047			16,093	29
17,170		77,507				30
1,557					63,998	31
36,473					271,022	32
3,823,004		8,922,909			352,192	33
						34
						35
						36
						37
						38
						39
						40
48,581,847	13,873,220	405,266,228			51,081,832	41

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	Montana:					
2	Property	2,831,820		5,671,723	5,669,957	
3	Corporate License-Income			298,361	279,176	9,731
4	Unemployment			397	397	
5	Energy License	60,000		194,594	194,594	
6	Wholesale Energy	42,000		138,648	138,648	
7	Subtotal	2,933,820		6,303,723	6,282,772	9,731
8						
9	Nevada:					
10	Commerce Tax	13,821		40,369	36,190	
11	Subtotal	13,821		40,369	36,190	
12						
13	New Mexico:					
14	Property			21,633	21,633	
15	Income			155,846	149,337	-407
16	Subtotal			177,479	170,970	-407
17						
18	Oregon:					
19	Property		12,518,813	25,777,048	26,041,557	
20	Unemployment	63,630		1,319,015	1,324,222	
21	Excise-Income			21,069,576	19,573,491	1,978,163
22	City of Portland-Income			71,402	56,912	1,745
23	Department of Energy		867,018	1,728,773	1,723,510	
24	Tri-Met	383,739		1,010,292	1,001,912	
25	Lane County			1,330	1,330	
26	Franchise	4,759,730		30,081,587	30,288,639	
27	Subtotal	5,207,099	13,385,831	81,059,023	80,011,573	1,979,908
28						
29	Texas:					
30	Unemployment			32	32	
31	Subtotal			32	32	
32						
33	Utah:					
34	Property	731,971		77,556,631	77,546,589	
35	Income			14,683,340	13,192,326	856,550
36	Unemployment	3,084		68,116	69,462	
37	Navajo Nation					
38	Use	324,524		3,714,304	3,720,051	
39	Subtotal	1,059,579		96,022,391	94,528,428	856,550
40						
41	TOTAL	46,331,988	13,392,342	456,348,060	382,773,438	71,805,641

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 2018/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
2,833,586		5,671,723				2
9,454		296,890			1,471	3
					397	4
60,000		194,594				5
42,000		138,648				6
2,945,040		6,301,855			1,868	7
						8
						9
18,000		40,369				10
18,000		40,369				11
						12
						13
		21,633				14
6,916		155,383			463	15
6,916		177,016			463	16
						17
						18
228,143	13,011,465	24,518,234			1,258,814	19
58,423					1,319,015	20
-482,078		20,969,224			100,352	21
12,745		71,065			337	22
	861,755	1,728,773				23
392,119					1,010,292	24
					1,330	25
4,552,678		30,081,587				26
4,762,030	13,873,220	77,368,883			3,690,140	27
						28
						29
					32	30
					32	31
						32
						33
742,013		77,396,644			159,987	34
634,464		14,574,136			109,204	35
1,738					68,116	36
						37
318,777					3,714,304	38
1,696,992		91,970,780			4,051,611	39
						40
48,581,847	13,873,220	405,266,228			51,081,832	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 2018/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	Washington:					
2	Property	11,700,000		12,172,957	11,872,957	
3	Unemployment	1,186		27,748	28,214	
4	Business & Occupation	3,100		25,685	25,485	
5	Public Utility	1,295,000		12,431,865	14,210,492	
6	Natural Gas Use Tax	226,034		1,619,654	1,706,532	
7	Use	41,972		554,696	494,620	
8	Forest Excise Tax			19,026	19,026	
9	Subtotal	13,267,292		26,851,631	28,357,326	
10						
11	Wyoming:					
12	Property	8,411,110		17,108,388	16,965,348	
13	Wind Generation Tax	1,787,702		2,064,726	1,820,812	
14	Unemployment	2,490		104,290	104,115	
15	Franchise	279,000		1,907,930	1,899,730	
16	Use	84,728		1,296,407	1,155,609	
17	Annual Report			70,783	70,783	
18	Subtotal	10,565,030		22,552,524	22,016,397	
19						
20	State Other:	2,603		-2,603		
21						
22	Miscellaneous:					
23	Goshute Possessory			25,900	25,900	
24	Sho-Ban Possessory			292,630	292,630	
25	Navajo Possessory	7,163		14,635	14,481	
26	Ute Possessory			43,893	43,893	
27	Crow Possessory			72,000		
28	Umatilla Possessory			68,133	68,133	
29	Subtotal	9,766		514,588	445,037	
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	46,331,988	13,392,342	456,348,060	382,773,438	71,805,641

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.
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8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
12,000,000		11,892,268			280,689	2
720					27,748	3
3,300		25,685				4
-483,627		12,431,865				5
139,156					1,619,654	6
102,048					554,696	7
					19,026	8
11,761,597		24,349,818			2,501,813	9
						10
						11
8,554,150		16,790,752			317,636	12
2,031,616		2,064,726				13
2,665					104,290	14
287,200		1,907,930				15
225,526					1,296,407	16
		70,783				17
11,101,157		20,834,191			1,718,333	18
						19
		-2,603				20
						21
						22
		25,900				23
		292,630				24
7,317		14,635				25
		43,893				26
72,000		72,000				27
		68,133				28
79,317		514,588				29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
48,581,847	13,873,220	405,266,228			51,081,832	41

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

Represents a reclassification of the balance from Account 146, Accounts receivable from associated companies.

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

Account 409.2, Income taxes, 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 from Account 143, Other accounts receivable.

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

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

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

$135,403 Account 408.2, Taxes other than income taxes, other income and deductions
1,430 Account 589, Rents
$136,833

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 the balance from Account 146, Accounts receivable from associated companies.

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

Account 409.2, Income taxes, 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

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

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

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

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

Represents a reclassification of the balance from Account 146, Accounts receivable from associated companies.

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

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

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

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

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

Charged to same account as related goods.

Schedule Page: 262.1 Line No.: 3 Column: f

Represents a reclassification of the balance from Account 146, Accounts receivable from associated companies.

Schedule Page: 262.1 Line No.: 3 Column: l

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

Schedule Page: 262.1 Line No.: 4 Column: l

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

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

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

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

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

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

Represents back taxes payable for leased property.

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

$ 25,730	Account 408.2, Taxes other than income taxes, other income and deductions
453,036	Account 589, Rents
780,048	Account 107, Construction work in progress
$1,258,814	

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

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

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

Represents a reclassification of the balance from Account 146, Accounts receivable from associated companies.

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

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

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

Represents a reclassification of the balance from Account 146, Accounts receivable from associated companies.

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

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

Schedule Page: 262.1 Line No.: 24 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.: 30 Column: l

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

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

$ 65,202	Account 408.2, Taxes other than income taxes, other income and deductions
94,785	Account 107, Construction work in progress
$ 159,987	

Schedule Page: 262.1 Line No.: 35 Column: f

Represents a reclassification of the balance from Account 146, Accounts receivable from associated companies.

Schedule Page: 262.1 Line No.: 35 Column: l

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

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

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

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

Charged to same account as related goods.

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

$ 51,177 Account 408.2, Taxes other than income taxes, other income and deductions

229,512 Account 107, Construction work in progress
$ 280,689

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

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

Schedule Page: 262.2 Line No.: 5 Column: g

Represents a prepayment of public utility tax resulting from customer payments for solar activity in the state.

Schedule Page: 262.2 Line No.: 6 Column: l

Account 151, Fuel stock

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

Charged to same account as related goods.

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

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

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

$ 6,824 Account 408.2, Taxes other than income taxes, other income and deductions
13,870 Account 589, Rents
296,942 Account 107, Construction work in progress
$ 317,636

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

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

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

Charged to same account as related goods.

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 2018/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	12,068,837			411.4,420	3,188,457	
6	30%	234,071			420	11,695	
7	Idaho	96,461			411.4,420	13,689	
8	TOTAL	12,399,369				3,213,841	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11	Idaho	3,270,954	190	986,865	420	174,907	45,337
12	Total Nonutility	3,270,954		986,865		174,907	45,337
13							
14							
15							
16							
17							
18							
19							
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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 2018/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
8,880,380	38.82 and 30		5
222,376	24		6
82,772	38.82 and 30		7
9,185,528			8
			9
			10
4,128,249	30		11
4,128,249			12
			13
			14
			15
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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%	$11,967,631	-	$ -	411.4(1)	$3,144,173	$ -	$ 8,823,458	38.82
10%	101,206	-	-	420(2)	44,284	-	56,922	30
	$12,068,837		$ -		$3,188,457	$ -	$ 8,880,380	

(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	$ 49,502	-	$ -	411.4(1)	$ 7,842	$ -	$ 41,660	38.82
Idaho	46,959	-	-	420(2)	5,847	-	41,112	30
	$ 96,461		$ -		$ 13,689	$ -	$ 82,772	

(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 debited 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 2018/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	5,726,612	131	156,000	3,750	5,574,362
2	Reclamation Costs - Trapper Mine	6,252,483			245,698	6,498,181
3	Western Coal Carriers Benefits					
4	Obligation	10,581,000	131	686,081	584,081	10,479,000
5	Deferred Compensation Plans	9,411,956	131	914,766	112,287	8,609,477
6	Long-Term Incentive Plan	16,111,099	131	103,937	4,744,238	20,751,400
7	Regulated Environmental					
8	Liabilities	52,303,713	131,182.3	8,171,087	11,374,014	55,506,640
9	Non-Regulated Environmental					
10	Liabilities	1,966,644	131	242,494	222,863	1,947,013
11	Unearned Joint Use					
12	Pole Contact Revenue	2,924,163	454	6,156,452	6,108,992	2,876,703
13	Misc. Security Deposits	75,675	415	52,177	95,809	119,307
14	Lease Incentives	694,303	101,931	538,993		155,310
15	Cowlitz/Lewis River O&M (1)	124,388	539	301,705	303,973	126,656
16	Employee Housing Security Deposits	19,900	131	2,800	1,800	18,900
17	Cogeneration Bonds-Sunnyside	413,417				413,417
18	Transmission Security Deposits	4,913,000	131	3,891,000	6,713,000	7,735,000
19	Transmission Service Deposits	509,217	131,235,456	859,931	2,686,262	2,335,548
20	MCI F.O.G. Wire Lease (1)	557,390	454	3,347,401	3,348,013	558,002
21	Unamortized Contract Values	82,395,248	242	14,940,726		67,454,522
22	Accrued Right-of-Way Obligations	3,443,821	131	1,626,707	603,178	2,420,292
23	Facility Use Fee	93,995	456	102,714	894,883	886,164
24	Energy Supply Management					
25	Deferral (1)	379,167	456	350,000	550,000	579,167
26	Deer Creek Accrued Royalties	5,463,429			1,719,528	7,182,957
27	Deferred Revenue - Other				291,664	291,664
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
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43						
44						
45						
46						
47	TOTAL	204,360,620		42,444,971	40,604,033	202,519,682

Schedule Page: 269 Line No.: 12 Column: a

The weighted average remaining life is one year.

Schedule Page: 269 Line No.: 14 Column: a

The weighted average remaining life is five years.

Schedule Page: 269 Line No.: 23 Column: a

The weighted average remaining life is 14 years.

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 2018/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	185,416,334	2,265,332	7,342,236
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	185,416,334	2,265,332	7,342,236
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)	185,416,334	2,265,332	7,342,236
18	Classification of TOTAL			
19	Federal Income Tax	151,178,573	885,628	5,025,064
20	State Income Tax	34,237,761	1,379,704	2,317,172
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 2018/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
						180,339,430	4
							5
							6
							7
						180,339,430	8
							9
							10
							11
							12
							13
							14
							15
							16
						180,339,430	17
							18
						147,039,137	19
						33,300,293	20
							21

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 2018/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	2,972,737,275	279,489,640	467,380,758
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	2,972,737,275	279,489,640	467,380,758
6	Nonutility			
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	2,972,737,275	279,489,640	467,380,758
10	Classification of TOTAL			
11	Federal Income Tax	2,447,858,515	176,934,385	353,439,354
12	State Income Tax	524,878,760	102,555,255	113,941,404
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
		182.3,254	311,913,302	182.3,254	437,647,211	2,910,580,066	2
							3
							4
			311,913,302		437,647,211	2,910,580,066	5
							6
							7
							8
			311,913,302		437,647,211	2,910,580,066	9
							10
			308,787,481		434,881,638	2,397,447,703	11
			3,125,821		2,765,573	513,132,363	12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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	260,766,772	28,826,479	28,997,472
4	Other	12,148,155	15,594,037	16,528,823
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	272,914,927	44,420,516	45,526,295
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)	272,914,927	44,420,516	45,526,295
20	Classification of TOTAL			
21	Federal Income Tax	222,771,074	36,830,033	37,744,500
22	State Income Tax	50,143,853	7,590,483	7,781,795
23	Local Income Tax			

NOTES

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
51,384,019	55,214,757		3,236,752		19,845,448	273,373,737	3
7,430,630	6,907,637	190,283	31,428	190,283	710,839	12,415,773	4
							5
							6
							7
							8
58,814,649	62,122,394		3,268,180		20,556,287	285,789,510	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
58,814,649	62,122,394		3,268,180		20,556,287	285,789,510	19
							20
47,919,414	50,632,882		2,698,707		16,807,379	233,251,811	21
10,895,235	11,489,512		569,473		3,748,908	52,537,699	22
							23

NOTES (Continued)

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

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

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

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

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/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 - CA	1,175,496	440,442,444	2,257,015	4,004,336	2,922,817
2	DSM Balancing Account - ID	1,127,251	440,442,444	4,747,062	5,160,875	1,541,064
3	DSM Balancing Account - UT				13,057,310	13,057,310
4	DSM Balancing Account - WA				1,757,029	1,757,029
5	DSM Balancing Account - WY				1,594,641	1,594,641
6	Oregon Energy Conservation Charge	3,772,072	440,442,444	33,629,829	34,233,084	4,375,327
7	Deferred Excess Net Power Costs - UT	3,999,381	182.3	3,999,381		
8	Deferred Excess Net Power Costs - WA	18,419,803	555	2,257,755	6,904,167	23,066,215
9	Deferred Excess Net Power Costs - WY	7,899,057	555,182.3	7,959,227	60,170	
10	Decoupling Mechanism - WA	1,254,992	440,442	884,229	2,951,338	3,322,101
11	Income Tax Reg. Liability - Flow Through - WA	193,304			545,628	738,932
12	Investment Tax Credit Regulatory Liability	3,194,547	190	838,704	3,215	2,359,058
13	Deferred Income Tax Electric	1,956,616,227	190,282	617,985,956	461,420,339	1,800,050,610
14	Excess Income Tax Deferral		182.3	3,425,023	71,768,801	68,343,778
15	Tax on Bonus Depreciation - WY	1,462,493	928	28,300	632,631	2,066,824
16	Other Postretirement	10,385,290		10,971,133	585,843	
17	Depreciation Study Deferral - ID				86,905	86,905
18	Asset Retirement Obligations Reg. Difference	4,070,978	230	649,526		3,421,452
19	Greenhouse Gas Allowance Compliance - CA	2,338,747	131,456,555	16,156,640	14,496,746	678,853
20	Solar on Multifamily Afforable Housing - CA		456	14,370	2,710,675	2,696,305
21	Solar Feed-In Tariff Deferral - CA	1,087,425		464,195		623,230
22	Solar Incentive Program - UT	14,398,860	440,442,444	3,478,682	3,337,997	14,258,175
23	STEP Pilot Program - UT	5,487,979		4,016,658	8,263,225	9,734,546
24	Independent Evaluator Costs - UT	247,437	131	139,555		107,882
25	Utah Home Energy Lifeline	1,578,414		288,442	220,583	1,510,555
26	Washington Low Income Program	1,378,081		874,054		504,027
27	California Energy Savings Assistance Program	546,846		462,696	351,114	435,264
28	FERC Rate True-up - OR (3)	24,797,198	456	4,306,685	9,965,352	30,455,865
29	BPA Balancing Account - ID	3,583,616	440,442	220,266		3,363,350
30	BPA Balancing Account - WA	643,076	440,442	173,130		469,946
31	Blue Sky - CA	279,970	440,442	65,538		214,432
32	Blue Sky - OR	2,138,183			425,292	2,563,475
33	Blue Sky - ID	196,171			45,363	241,534
34	Blue Sky - UT	8,521,484			1,469,548	9,991,032
35	Blue Sky - WA	265,908			114,994	380,902
36	Blue Sky - WY	432,112			34,231	466,343
37	Depreciation Deferral - OR	4,014,249			1,209,099	5,223,348
38	Deferred Steam Accel. Depreciation - WA	14,422,807			12,611,581	27,034,388
39	Merwin Fish Collector Project - WA	3,432				3,432
40	Direct Access 5-Year Opt Out - OR (10)	1,943,382	442	1,729,274	3,419,751	3,633,859
41	TOTAL	2,101,876,268		722,023,325	664,386,963	2,044,239,906

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 2018/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	Transportation Electrification Program - CA				457,600	457,600
2	Oregon Clean Fuels Program				487,500	487,500
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
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35						
36						
37						
38						
39						
40						
41	TOTAL	2,101,876,268		722,023,325	664,386,963	2,044,239,906

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

Weighted average remaining life is approximately three years for deferred excess net power cost mechanisms being amortized.

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

Weighted average remaining life is approximately one year for deferred excess net power cost mechanisms being amortized.

Schedule Page: 278 Line No.: 12 Column: a

Weighted average remaining life is 39 years.

Schedule Page: 278 Line No.: 13 Column: a

Amounts primarily represent income tax liabilities related to the federal tax rate change from 35% to 21% that are probable to be passed on to customers, offset by income tax benefits related to certain property-related basis differences and other various differences that were previously passed on to customers and will be included in regulated rates when the temporary differences reverse.

Schedule Page: 278 Line No.: 16 Column: a

Weighted average remaining life of portion being amortized is 13 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: 278 Line No.: 16 Column: c

Other postretirement costs are associated with labor and generally charged to operations and maintenance expense and construction work in progress. Other postretirement remeasurement date changes and Wyoming's share of settlement losses are charged to Account 926, Employee pensions and benefits.

Schedule Page: 278 Line No.: 21 Column: c

Account 182.3, Other regulatory assets
Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting

Schedule Page: 278 Line No.: 23 Column: c

Account 107, Construction work in progress
Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting

Schedule Page: 278 Line No.: 25 Column: c

Account 131, Cash
Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting

Schedule Page: 278 Line No.: 26 Column: c

Account 131, Cash
Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting

Schedule Page: 278 Line No.: 27 Column: c

Account 131, Cash
Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting

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	1,774,237,100	1,884,431,867
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,541,492,719	1,569,999,446
5	Large (or Ind.) (See Instr. 4)	1,322,455,444	1,373,506,114
6	(444) Public Street and Highway Lighting	18,155,451	19,817,707
7	(445) Other Sales to Public Authorities		3,322,249
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	4,656,340,714	4,851,077,383
11	(447) Sales for Resale	254,214,730	217,427,479
12	TOTAL Sales of Electricity	4,910,555,444	5,068,504,862
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	4,910,555,444	5,068,504,862
15	Other Operating Revenues		
16	(450) Forfeited Discounts	9,811,199	10,272,123
17	(451) Miscellaneous Service Revenues	6,172,987	5,342,009
18	(453) Sales of Water and Water Power	54,615	54,199
19	(454) Rent from Electric Property	17,246,955	18,455,411
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	29,900,870	25,295,388
22	(456.1) Revenues from Transmission of Electricity of Others	116,616,886	115,041,634
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	179,803,512	174,460,764
27	TOTAL Electric Operating Revenues	5,090,358,956	5,242,965,626

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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
16,227,117	16,625,426	1,651,326	1,622,276	2
				3
18,078,160	17,665,137	211,800	208,378	4
20,679,901	20,756,851	33,186	33,200	5
130,278	141,243	3,501	3,470	6
	61,165			7
				8
				9
55,115,456	55,249,822	1,899,813	1,867,324	10
8,309,472	7,218,497			11
63,424,928	62,468,319	1,899,813	1,867,324	12
				13
63,424,928	62,468,319	1,899,813	1,867,324	14

Line 12, column (b) includes $ 229,061,000 of unbilled revenues.

Line 12, column (d) includes 2,887,422 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 PacifiCorp's 12/31/2017 FERC 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:

	2018	2017
Account service charges - application fees, disconnects, reconnects and returned check charges	$ 5,274,993	$ 4,304,054
Customer contract flat rate billings and facility buyout charges	873,886	999,199

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:

	2018	2017
Wind-based ancillary services	$ 11,169,083	$ 9,781,935
Amortization of California greenhouse gas allowance revenue	9,591,652	8,113,014
Flyash/by-product sales	4,258,230	4,491,627
Renewable energy credit sales, including amortization and deferrals	3,300,207	1,088,549
Revenue from generation interconnection and transmission service request studies	1,659,764	1,784,329
Phase shifting equipment fee from Western Electricity Coordinating Council	1,380,032	(a)
Steam sales	689,865	483,973
Timber sales	506,102	1,269,886
Energy exchange credits	453,590	395,600
Maintenance charges for work on transmission facilities	432,874	676,198
Revenue from other requested customer studies	266,676	(a)
Net profit on sales of materials and supplies inventory	(a)	578,093
Service territory fixed cost recovery fee	(a)	303,473
Deferral of Oregon retail customers' allocated share of the incremental Open Access Transmission Tariff revenues associated with FERC Docket No. ER11-3643-000, net of amortization	(4,129,687)	(3,978,799)

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

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SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RESIDENTIAL SALES					
2	CALIFORNIA					
3	06CHCK000R - CA RES CHECK M			1		
4	06LNX00311 - LINE EXT 80% GTY		1,636			
5	06NETMT135 - CA RES NET MTR	1,824	213,444	353	5,167	0.1170
6	06OALT015R - OUTD AR LGT SR	271	77,727	291	931	0.2868
7	06RESD000D - RES SRVC	164,209	21,708,852	17,349	9,465	0.1322
8	06RESD00DN - DEL NORTE CTY	72,950	9,757,412	6,756	10,798	0.1338
9	06RESD0DM9 - MULTI FAMILY	162	17,412	7	23,143	0.1075
10	06RESD0DS8 - MULT FAM SBMET	1,631	175,285	16	101,938	0.1075
11	06RESDDL06 - CA LOW INCOME	114,559	15,213,205	11,323	10,117	0.1328
12	06RGNSV025 - CA SMALL GEN	1,347	292,726	475	2,836	0.2173
13	REVENUE_ACCT ADJ		-1,486,387			
14	INCOME TAX DEFERRAL ADJ		-1,580,276			
15	DSM REVENUE-RESIDENTIAL		1,156,912			
16	BLUE SKY REV-RESIDENTIAL		132,970			
17	SOLAR FEED-IN REVENUE		6,862			
18	UNBILLED REV - UNCOLLECTIBLE		-3,000			
19	UNBILLED REVENUE	12,955	1,351,000			0.1043
20						
21	IDAHO					
22	07LNX00010 - MNTHLY 80%GTY		1,153			
23	07LNX00035 - ADV 80%MO GTY		2,826			
24	07NETMT135 - ID RES NET MTR	4,197	366,486	490	8,565	0.0873
25	07OALCO007 - CUST OWN LIGHT	10	3,827	1	10,000	0.3827
26	07OALT07AR - SECURITY AR LG	96	39,379	120	800	0.4102
27	07RESD0001 - RES SRVC	492,571	56,089,904	52,204	9,436	0.1139
28	07RESD0036 - RES SRVC-OPTIO	194,240	19,047,622	11,629	16,703	0.0981
29	07RGNSV06A - LRG GEN SVC-RES	219	17,130	2	109,500	0.0782
30	07RGNSV23A - SM GEN SVC-RES	9,053	1,016,611	1,059	8,549	0.1123
31	07RNM23135 - NET MTR SMALL	68	5,404	3	22,667	0.0795
32	REVENUE_ACCT ADJ		-234,719			
33	INCOME TAX DEFERRAL ADJ		-789,050			
34	DSM REVENUE-RESIDENTIAL		2,006,223			
35	BLUE SKY REV-RESIDENTIAL		11,825			
36	UNBILLED REV - UNCOLLECTIBLE		-7,000			
37	UNBILLED REVENUE	2,786	50,000			0.0179
38						
39	OREGON					
40	01CHCK000R - RES CHECK MTR			1		
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
42	Total Unbilled Rev.(See Instr. 6)	-218,057	-26,093,000	0	0	0.1197
43	TOTAL	55,115,456	4,722,801,747	1,899,813	29,011	0.0857

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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.
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3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	01COST0004 - 01RESD0004	4,940,665	301,985,312			0.0611
2	01COSTR023 - RES GEN SRV CST	94,177	5,801,649			0.0616
3	01COSTR028 - OR RES GEN SVC	49,277	3,028,023			0.0614
4	01FXRENEWR - FIXED		-3			
5	01HABIT004 - 01RESD0004	53,124	3,188,792			0.0600
6	01HABTR023 - RES GEN SVC HAB	202	12,777			0.0633
7	01LNX00102 - LINE EXT 80% G		10,013			
8	01LNX00109 - REF/NREF ADV +		4,727			
9	01LNX00300 - LINE EXT 80% GTY		168			
10	01NETMT135 - NET METERING		2,226,588	5,250		
11	01NMTOU135 - TOU NET		61,786	27		
12	01OALTB15R - OR OUTD AR LGT	2,105	346,256	2,432	866	0.1645
13	01PTOU0004 - 01RESD0004	15,688	991,013			0.0632
14	01PTOU0005 - 01RESEV05T TOU	5	255			0.0510
15	01RENEW004 - 01RESD0004	381,112	22,536,235			0.0591
16	01RENWR023 - RENEW USAGE	706	42,828			0.0607
17	01RESD0004 - RES SRVC		292,237,279	497,292		
18	01RESD004T - RES TIME OPT		755,445	1,045		
19	01RESEV05T - RES ELECT		332	1		
20	01RGNSB023 - SMALL GENERAL		7,217,335	16,879		
21	01RGNSB028 - GENERAL SVC > 30		1,356,985	216		
22	01RGNSB023 - SMALL GENERAL		43,626	110		
23	01RGNSB028 - GENSVC > 30 KW		50,498	2		
24	01UPPL000R - BASE SCH FALL			2		
25	01VIR04136 - VOLUME INCENTIVE		377,100	471		
26	REVENUE_ACCT ADJ		-3,224,728			
27	INCOME TAX DEFERRAL ADJ		-20,274,470			
28	OR GAIN ON SALE OF ASSET		11,230			
29	DSM REVENUE-RESIDENTIAL		18,829,173			
30	BLUE SKY REV-RESIDENTIAL		402,126			
31	SOLAR FEED-IN REVENUE		2,028,145			
32	UNBILLED REVENUE	19,163	1,634,000			0.0853
33						
34	UTAH					
35	08BLSKY01R - BLUESKY ENERGY		-9			
36	08CFR00001 - MTH FACILITY S		735			
37	08CGENR136 - UT RES TRANS	644	68,058	175	3,680	0.1057
38	08CGN03136 - UT LOW INC RES	7	738	2	3,500	0.1054
39	08CGR01136 - UT RES TRANS	6,974	737,812	962	7,249	0.1058
40	08CGR02136 - UT RES TOU TRANS	3	368	1	3,000	0.1227
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
42	Total Unbilled Rev.(See Instr. 6)	-218,057	-26,093,000	0	0	0.1197
43	TOTAL	55,115,456	4,722,801,747	1,899,813	29,011	0.0857

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1	08CGR03136 - UT LOW INC RES	89	9,378	11	8,091	0.1054
2	08CGR23136 - RES SM GEN SVC	13	1,320			0.1015
3	08CHCK000R - UT RES CHECK M			1		
4	08COOLKPRR - COOL KEEPER			98,254		
5	08LNX00001 - MTHLY 80% GUAR		2,917			
6	08LNX00005 - MTHLY MIN GUAR		396			
7	08LNX00013 - 80% MNTHLY MIN		26,974			
8	08LNX00108 - ANN COST MTHLY		1,656			
9	08MHTP0006 - MOBILE HOME &	12,093	900,548	8	1,511,625	0.0745
10	08MHTP0023 - MOBILE HOME &	124	9,715	1	124,000	0.0783
11	08NETMT135 - NET MTR	109,999	13,105,091	28,984	3,795	0.1191
12	08NMT03135 - LOW INC RES	880	96,183	173	5,087	0.1093
13	08OALT007R - SECURITY AR LG	2,321	644,715	2,356	985	0.2778
14	08PTLD000R - POST TOP LIGHT	1	105	2	500	0.1050
15	08RCG23136 - RES NET MTR, SM	4	439	1	4,000	0.1098
16	08RESD0001 - RES SRVC	6,586,081	707,531,284	750,967	8,770	0.1074
17	08RESD0002 - RES SRVC-OPTIO	3,241	345,112	383	8,462	0.1065
18	08RESD0003 - LIFELINE PRGRM	169,849	17,968,836	22,827	7,441	0.1058
19	08RESD002E - RES ELECT	2,012	172,491	147	13,687	0.0857
20	08RGNSV006 - GEN SRVC-RES	116,776	8,710,631	270	432,504	0.0746
21	08RGNSV023 - GEN SRVC-RES	99,540	10,702,826	13,487	7,380	0.1075
22	08RGNSV06A - UT SM GEN SVC	10,140	881,237	26	390,000	0.0869
23	08RGNSV06B - UT SM GEN SVC	33	4,143	1	33,000	0.1255
24	08RNM06135 - UT NET MTR, GEN	3,657	313,718	13	281,308	0.0858
25	08RNM23135 - UT NET MTR, GEN	1,062	147,383	414	2,565	0.1388
26	08RNM6A135 - RES GEN SVC NET	3	1,795	1	3,000	0.5983
27	08SSLR0001 - RES SUBSCRB	29,395	3,299,477			0.1122
28	08SSLR0003 - LOW INCOME	289	31,652	26	11,115	0.1095
29	08SSLRRG23 - SM GEN SUBSCR	56	7,616	16	3,500	0.1360
30	08UPPL000R - BASE SCH FALL			4		
31	REVENUE_ACCT ADJ		-1,070,429			
32	REVENUE ADJ - DEF NPC		520,102			
33	DSM REVENUE-RESIDENTIAL		2,187,064			
34	BLUE SKY REV-RESIDENTIAL		1,254,710			
35	SOLAR FEED-IN REVENUE		1,912,182			
36	UNBILLED REV - UNCOLLECTIBLE		23,000			
37	UNBILLED REVENUE	-62,147	-7,909,000			0.1273
38						
39	WASHINGTON					
40	02BLSKY01R - BLUESKY ENERGY		-2			
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
42	Total Unbilled Rev.(See Instr. 6)	-218,057	-26,093,000	0	0	0.1197
43	TOTAL	55,115,456	4,722,801,747	1,899,813	29,011	0.0857

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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	02LNX00109 - REF/NREF ADV +		1,839			
2	02NETMT135 - WA RES NET MTR	9,231	943,625	953	9,686	0.1022
3	02OALTB15R - WA OUTD AR LGT	953	151,628	1,050	908	0.1591
4	02RESD0016 - WA RES SRVC	1,453,252	139,892,718	101,774	14,279	0.0963
5	02RESD0017 - BILL ASSISTANC	72,685	6,997,352	4,903	14,825	0.0963
6	02RESD0018 - WA 3 PHASE RES	2,085	221,147	80	26,063	0.1061
7	02RESD018X - WA 3 PHASE RES	331	34,409	14	23,643	0.1040
8	02RGNSB024 - WA SM GEN SVC	20,300	2,506,226	3,428	5,922	0.1235
9	02RGNSB036 - RES LRG GEN SVC	1,448	116,399	2	724,000	0.0804
10	02RNM24135 - RES NET MTR SM	73	9,735	17	4,294	0.1334
11	02ZZMERGCR - MERGER CREDITS		-4			
12	REVENUE_ACCT ADJ		-9,629,568			
13	REVENUE ADJ - DEF NPC		60,142			
14	INCOME TAX DEFERRAL ADJ		-3,342,707			
15	ALT REVENUE PROGRAM ADJ		217,345			
16	DSM REVENUE-RESIDENTIAL		4,810,520			
17	BLUE SKY REV-RESIDENTIAL		131,576			
18	UNBILLED REV - UNCOLLECTIBLE		14,000			
19	UNBILLED REVENUE	-40,010	-5,588,000			0.1397
20						
21	WYOMING					
22	05LNX00102 - LINE EXT 80% G		792			
23	05LNX00109 - REF/NREF ADV +		32			
24	05NETMT135 - EXP PARTIAL REQ	1,758	210,387	201	8,746	0.1197
25	05OALT015R - OUTD AR LGT SR	835	115,800	987	846	0.1387
26	05RESD0002 - WY RES SRVC	876,499	95,456,624	101,984	8,594	0.1089
27	05RGNSV025 - WY SM GEN SVC	9,236	1,127,892	1,521	6,072	0.1221
28	09OALT207R - SECURITY AR LG		156	1		
29	REVENUE_ACCT ADJ		178,219			
30	REVENUE ADJ - DEF NPC		-80,632			
31	INCOME TAX DEFERRAL ADJ		-766,459			
32	DSM REVENUE-RESIDENTIAL		926,228			
33	DSM REVENUE-RES GEN SVC		37,350			
34	BLUE SKY REV-RESIDENTIAL		144,740			
35	UNBILLED REV - UNCOLLECTIBLE		-21,000			
36	UNBILLED REVENUE	-13,718	-1,923,000			0.1402
37	05NETMT135 - EXP PARTIAL REQ	377	44,552	37	10,189	0.1182
38	05OALT015R - OUTD AR LGT SR	1	85	1	1,000	0.0850
39	05RESD0002 - WY RES SRVC	110,114	12,136,263	12,462	8,836	0.1102
40	05RGNSV025 - WY SML GEN SVC	440	74,192	143	3,077	0.1686
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
42	Total Unbilled Rev.(See Instr. 6)	-218,057	-26,093,000	0	0	0.1197
43	TOTAL	55,115,456	4,722,801,747	1,899,813	29,011	0.0857

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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.
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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	09OALT207R - SECURITY AR LG	71	17,146	84	845	0.2415
2	09RES00002			1		
3	09RESD0002			4		
4	DSM REVENUE-RESIDENTIAL		161,953			
5	DSM REVENUE-RES GEN SVC		2,815			
6	BLUE SKY REV-RESIDENTIAL		19,720			
7	UNBILLED REVENUE	-1,355	-162,000			0.1196
8						
9	LESS MULTIPLE BILLINGS			-123,641		
10						
11	TOTAL RESIDENTIAL SALES	16,227,117	1,774,237,100	1,651,326	9,827	0.1093
12						
13	COMMERCIAL SALES					
14	CALIFORNIA					
15	06GNSV0025 - CA GEN SRVC	52,392	9,512,511	6,530	8,023	0.1816
16	06GNSV025F - GEN SRVC-< 20	916	181,665	85	10,776	0.1983
17	06GNSV0A32 - GEN SRVC-20 KW	83,784	13,013,640	1,045	80,176	0.1553
18	06LGSV048T - LRG GEN SERV	28,559	2,955,114	8	3,569,875	0.1035
19	06LGSV0A36 - LRG GEN SRVC-O	61,821	8,119,831	152	406,717	0.1313
20	06LNX00102 - LINE EXT 80% G		5,646			
21	06LNX00109 - REF/NREF ADV +		102,730			
22	06LNX00110 - REF/NREF ADV +		13			
23	06LNX00311 - LINE EXT 80%		28,048			
24	06NMT25135 - GEN SVC NET	89	16,672	14	6,357	0.1873
25	06NMT32135 - GEN SVC NET	1,819	301,801	23	79,087	0.1659
26	06NMT36135 - GEN SVC NET	2,319	314,576	5	463,800	0.1357
27	06NMT48135 - GEN SVC NET	2,664	271,432	1	2,664,000	0.1019
28	06OALT015N - OUTD AR LGT SR	651	188,660	471	1,382	0.2898
29	06RCFL0042 - AIRWAY & ATHLE	152	35,012	37	4,108	0.2303
30	REVENUE_ACCT ADJ		-938,125			
31	INCOME TAX DEFERRAL ADJ		-988,161			
32	DSM REVENUE-COMMERCIAL		730,817			
33	BLUE SKY REV-COMMERCIAL		12,000			
34	SOLAR FEED-IN REVENUE		6,483			
35	UNBILLED REVENUE	-2,714	-485,000			0.1787
36						
37	IDAHO					
38	07CISH0019 - COMM & IND SPA	4,837	417,536	89	54,348	0.0863
39	07GNSV0006 - GEN SRVC-LRG P	246,923	20,045,205	1,016	243,034	0.0812
40	07GNSV0009 - GEN SRVC-HI VO	43,034	2,706,666	2	21,517,000	0.0629
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
42	Total Unbilled Rev.(See Instr. 6)	-218,057	-26,093,000	0	0	0.1197
43	TOTAL	55,115,456	4,722,801,747	1,899,813	29,011	0.0857

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1	07GNSV0023 - GEN SRVC-SML P	152,010	15,065,211	6,939	21,907	0.0991
2	07GNSV0035 - GEN SRVCOPTION	261	15,982	2	130,500	0.0612
3	07GNSV006A - GEN SRVC-LRG P	24,600	2,156,662	181	135,912	0.0877
4	07GNSV023A - GEN SRVC-SML P	27,776	2,730,404	1,279	21,717	0.0983
5	07GNSV023F - GEN SRVC SML P	7	1,794	4	1,750	0.2563
6	07LNX00010 - MNTHLY 80%GUAR		20,892			
7	07LNX00015 - ANNUAL 80%GUAR		528			
8	07LNX00035 - ADV 80%MO GUAR		239,105			
9	07LNX00040 - ADV+REFCHG+80%		36,706			
10	07LNX00300 - 80% MONTHLY MIN		3,632			
11	07LNX00311 - LINE EXT 80%		33,329			
12	07LNX00312 - ID LINE EXT		26,681			
13	07NMT06135 - ID NET MTR - LG	1,730	140,794	3	576,667	0.0814
14	07NMT23135 - ID NET MTR - SM	1,168	89,439	27	43,259	0.0766
15	07OALT007N - SECURITY AR LG	252	98,096	169	1,491	0.3893
16	07OALT07AN - SECURITY AR LG	10	3,913	10	1,000	0.3913
17	REVENUE_ACCT ADJ		-135,678			
18	INCOME TAX DEFERRAL ADJ		-560,569			
19	DSM REVENUE-COMMERCIAL		1,131,489			
20	BLUE SKY REV-COMMERCIAL		1,182	1		
21	UNBILLED REVENUE	8,512	601,000			0.0706
22						
23	OREGON					
24	01COST0023 - OR GEN SRV	1,007,550	59,877,993			0.0594
25	01COST0048 - 01LGSV0048	1,106,604	54,414,539			0.0492
26	01COST023F - OR GEN SRV	2,868	181,246			0.0632
27	01COSTB023 - OR GEN SRV	23,968	1,453,872			0.0607
28	01COSTEV45 - ELECT VEH DC	97	6,036			0.0622
29	01COSTL030 - OR LRG GEN SRV	1,137,902	60,073,225			0.0528
30	01COSTS028 - OR GEN SERV	1,925,524	118,556,810			0.0616
31	01GNSB0023 - OR GEN SRV BPA		1,607,346	2,869		
32	01GNSB0028 - OR GEN SRV, BPA		1,969,753	289		
33	01GNSB023T - OR GEN SRV - TOU		28,123	48		
34	01GNSEV45T - ELECT VEH DC		19,928	12		
35	01GNSV0023 - OR GEN SRV, < 30		54,429,438	58,101		
36	01GNSV0028 - OR GEN SRV > 30		57,360,041	9,056		
37	01GNSV023F - OR GEN SRV - FLAT	10,264	1,634,929	777	13,210	0.1593
38	01GNSV023M - OR GEN SRV,	80	8,106	2	40,000	0.1013
39	01GNSV023T - OR GEN SRV, TOU		164,043	196		
40	01GNSV0723 - OR GEN SVC DIR		5,702	2		
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
42	Total Unbilled Rev.(See Instr. 6)	-218,057	-26,093,000	0	0	0.1197
43	TOTAL	55,115,456	4,722,801,747	1,899,813	29,011	0.0857

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1	01GNSV0728 - OR GEN SVC DIR		84,401	6		
2	01GNSV0730 - OR GEN SVC DIR		1,902,534	14		
3	01GNSV0748 - LG GEN SVC DIR		8,855,568	3		
4	01HABT0023 - OR HABITAT	3,659	218,600			0.0597
5	01HABTB023 - OR HABITAT	21	1,304			0.0621
6	01LGSB0030 - GEN DEL SRV, > 200		877,338	19		
7	01LGSB0048 - LG GEN SVC > 1000		83,183	1		
8	01LGSV0030 - OR LRG GEN SRV, >		30,033,555	653		
9	01LGSV0048 - 1000KW AND OVR		18,828,687	90		
10	01LGSV028M - OR LGSV, <1000 Kw	522	46,903	1	522,000	0.0899
11	01LGSV048M - LRG GEN SRVC 1	60,556	3,833,190	1	60,556,000	0.0633
12	01LNX00100 - LINE EXT 60% G		1,841			
13	01LNX00102 - LINE EXT 80% G		742,408			
14	01LNX00103 - LINE EXT 80% G		8,706			
15	01LNX00105 - CNTRCT $ MIN GTY		11,371			
16	01LNX00109 - REF/NREF ADV +		1,189,152			
17	01LNX00110 - REF/NREF ADV +		7,104			
18	01LNX00120 - LINE EXT 60% GTY		1,353			
19	01LNX00300 - LINE EXT 80% GTY		257,553			
20	01LNX00311 - LINE EXT 80% GTY		201,338			
21	01LPRS047M - PART REQ SRVC	41,592	4,179,797	5	8,318,400	0.1005
22	01NM23T135 - OR NET MTR TOU		569			
23	01NMT23135 - OR NET MTR, GEN,		317,149	372		
24	01NMT28135 - OR NET MTR, GEN,		1,494,761	204		
25	01NMT30135 - OR NET MTR, GEN,		1,428,438	30		
26	01NMT48135 - NET MTR GEN SVC		410,990	3		
27	01OALT015N - OUTD AR LGT NR	5,289	787,514	2,764	1,914	0.1489
28	01OALTB15N - OR OUTD AR LGT	1,414	239,290	1,028	1,375	0.1692
29	01PTOU0023 - OR GEN SRV, TOU	2,982	178,579			0.0599
30	01PTOUB023 - OR GEN SRV, TOU	440	27,197			0.0618
31	01RCFL0054 - REC FIELD LGT	1,433	142,401	105	13,648	0.0994
32	01RENW0023 - OR RENW USAGE	12,750	772,586			0.0606
33	01RENWB023 - OR RENEWABLE	54	3,408			0.0631
34	01STDAY023 - OR DAY STD OFR,	3,626	230,650			0.0636
35	01STDAY028 - OR DAY STD OFF,	14,482	931,090			0.0643
36	01STDAY030 - OR STD DAY OFF,	5,634	324,937			0.0577
37	01VIR23136 - OR VOL INC <= 30		193,338	120		
38	01VIR28136 - OR VOL INC > 30 KW		604,257	90		
39	01VIR30136 - OR VOL INC > 200		314,232	8		
40	01VIR48136 - OR VOL INC > 1000		118,084	1		
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
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1	REVENUE_ACCT ADJ		-1,008,534			
2	INCOME TAX DEFERRAL ADJ		-18,675,614			
3	OR GAIN ON SALE OF ASSET		10,313			
4	DSM REVENUE-COMMERCIAL		13,154,714			
5	BLUE SKY REV-COMMERCIAL		505,539	100		
6	SOLAR FEED-IN REVENUE		1,724,899			
7	UNBILLED REVENUE	-104,235	-8,921,000			0.0856
8						
9	UTAH					
10	08ABL-NRES - APPLICANT BUILT		-13,884			
11	08CFR00051 - MTH FAC SRVCHG		29,955			
12	08CFR00052 - ANN FAC SVCCHG		2			
13	08CGN06136 - UT GEN SVC	199	19,570	1	199,000	0.0983
14	08CGN23136 - UT NET MTR SM	70	7,050	4	17,500	0.1007
15	08COOLKPRN - A/C DIRECT LOAD			2,242		
16	08GNSV0006 - GEN SRVC-DISTR	5,046,693	410,603,001	11,156	452,375	0.0814
17	08GNSV0008 - UT GEN SVC TOU >	940,199	67,007,808	129	7,288,364	0.0713
18	08GNSV0009 - GEN SRVC-HI VO	834,542	46,725,331	40	20,863,550	0.0560
19	08GNSV0023 - GEN SRVC-DISTR	1,245,349	120,684,728	73,254	17,000	0.0969
20	08GNSV006A - GEN SRVC-ENERG	246,363	28,544,422	1,947	126,535	0.1159
21	08GNSV006B - GEN SRVC-DEM&	3,397	332,910	14	242,643	0.0980
22	08GNSV006M - MNL DIST VOLTG	197	15,102	3	65,667	0.0767
23	08GNSV008M - UT GEN SVC TOU >	17,317	1,411,916	3	5,772,333	0.0815
24	08GNSV009A - GEN SRVC HI VO	27,185	1,774,054	2	13,592,500	0.0653
25	08GNSV009M - MANL HIGH VOLT	246,182	13,783,909	1	246,182,000	0.0560
26	08GNSV023F - GEN SRVC FIXED	1,313	183,984	129	10,178	0.1401
27	08GNSV023M - GNSV DIST VOLT	365	28,632	7	52,143	0.0784
28	08GNSV06AM - MNL ENERGY TOD	479	46,194	1	479,000	0.0964
29	08GNSV06MN - GNSV DIST VOLT	34,045	2,646,215	580	58,698	0.0777
30	08LNX00002 - MTHLY 80% GUAR		561,844			
31	08LNX00004 - ANNUAL 80%GUAR		60,728			
32	08LNX00006 - FIXD MTHLY MIN		2,462			
33	08LNX00014 - 80% MIN MNTHLY		1,744,673			
34	08LNX00017 - ADV/REF&80%ANN		267,385			
35	08LNX00158 - ANNUALCOST MTH		32,125			
36	08LNX00300 - LINE EXT 80% PLUS		176,493			
37	08LNX00310 - IRR, 80% ANNUAL		53,694			
38	08LNX00311 - LINE EXT 80%		287,160			
39	08LNX00312 - UT IRG LINE EXT		13,126			
40	08MONL0015 - MTR OUTDONIGHT	14,782	1,064,872	526	28,103	0.0720
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
42	Total Unbilled Rev.(See Instr. 6)	-218,057	-26,093,000	0	0	0.1197
43	TOTAL	55,115,456	4,722,801,747	1,899,813	29,011	0.0857

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1	08NMT06135 - UT NET MTR GEN	122,344	10,292,047	261	468,751	0.0841
2	08NMT08135 - NET MTR GEN SVC	112,048	7,837,640	12	9,337,333	0.0699
3	08NMT23135 - UT NET MTR, GEN,	8,907	942,388	759	11,735	0.1058
4	08NMT6A135 - NET MTR GEN SVC	9,127	1,218,024	83	109,964	0.1335
5	08OALT007N - SECURITY AR LG	7,464	1,702,529	3,975	1,878	0.2281
6	08POLE0075 - POLES W/LIGHT		141	1		
7	08PRSV031M - BKUP MNT&SUPPL	115,648	7,355,799	4	28,912,000	0.0636
8	08PTLD000N - POST TOP LIGHT	6	452	2	3,000	0.0753
9	08SSLR0006 - GEN SVC SUBSCR	3,834	437,376	11	348,545	0.1141
10	08SSLR0023 - SM GEN SVC	3,484	380,511			0.1092
11	08SSLR006A - GEN SVC TOU	42,492	4,048,415	309	137,515	0.0953
12	08TOSS0015 - TRAF & OTHER	3,029	314,158	1,035	2,927	0.1037
13	08TOSS015F - TRAFFIC SIG NM	171	15,257	20	8,550	0.0892
14	REVENUE_ACCT ADJ		-769,265			
15	REVENUE ADJ - DEF NPC		676,337			
16	DSM REVENUE-COMMERCIAL		2,809,040			
17	BLUE SKY REV-COMMERCIAL		245,758			
18	SOLAR FEED-IN REVENUE		2,488,770			
19	UNBILLED REVENUE	4,761	-1,271,000			-0.2670
20						
21	WASHINGTON					
22	02GNSB0024 - WA GEN SRVC DO	28,460	2,860,111	1,510	18,848	0.1005
23	02GNSB024F - GEN SRVC DOM/F	154	20,454	6	25,667	0.1328
24	02GNSB24FP - WA GEN SVC	178	84,000	76	2,342	0.4719
25	02GNSV0024 - WA GEN SRVC	480,239	45,912,256	14,246	33,710	0.0956
26	02GNSV024F - WA GEN SRVC-FL	1,070	153,783	104	10,288	0.1437
27	02LGSB0036 - LRG GEN SVC IRG	58,621	4,936,584	96	610,635	0.0842
28	02LGSV0036 - WA LRG GEN SRV	776,241	63,446,762	860	902,606	0.0817
29	02LGSV048T - LRG GEN SRVC 1	192,658	14,504,460	35	5,504,514	0.0753
30	02LNX00102 - LINE EXT 80% G		53,457			
31	02LNX00103 - LINE EXT 80% G		10,724			
32	02LNX00105 - CNTRCT $ MIN G		1,742			
33	02LNX00109 - REF/NREF ADV +		278,734			
34	02LNX00110 - REF/NREF ADV +		31,164			
35	02LNX00112 - YR INCURRED CH		669			
36	02LNX00300 - LINE EXT 80% G		7,766			
37	02LNX00311 - LINE EXT 80% GTY		51,215			
38	02LNX00312 - WA IRG LINE EXT		12,500			
39	02NMB24135 - WA NET METERING	16	2,803	6	2,667	0.1752
40	02NMT24135 - NET MTR, WA	3,300	323,122	89	37,079	0.0979
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
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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	02NMT36135 - WA NET MTR LRG	10,756	935,602	14	768,286	0.0870
2	02NMT48135 - WA LG SVC NET	10,591	795,715	2	5,295,500	0.0751
3	02OALT015N - WA OUTD AR LGT	1,457	215,657	770	1,892	0.1480
4	02OALTB15N - WA OUTD AR LGT	510	82,571	467	1,092	0.1619
5	02RCFL0054 - WA REC FIELD L	280	26,775	27	10,370	0.0956
6	REVENUE_ACCT ADJ		-9,563,913			
7	REVENUE ADJ - DEF NPC		56,695			
8	INCOME TAX DEFERRAL ADJ		-3,056,273			
9	ALT REVENUE PROGRAM ADJ		-2,552,754			
10	DSM REVENUE-COMMERCIAL		4,231,357			
11	BLUE SKY REV-COMMERCIAL		15,505	1		
12	UNBILLED REVENUE	3,152	275,000			0.0872
13						
14	WYOMING					
15	05CHCK000N - WY NRES CHECK			1		
16	05GNSV0025 - WY GEN SRVC	220,598	21,629,435	17,915	12,314	0.0980
17	05GNSV0028 - GEN SVC > 15 KW	854,347	71,792,687	3,177	268,916	0.0840
18	05GNSV025F - GEN SRVC-FL RA	996	159,475	174	5,724	0.1601
19	05LGSV0046 - WY LRG GEN SRV	159,566	11,341,707	14	11,397,571	0.0711
20	05LGSV048T - LRG GENSRV TIM	11,480	905,538	1	11,480,000	0.0789
21	05LNX00100 - LINE EXT 60% GTY		14,972			
22	05LNX00102 - LINE EXT 80% GTY		590,699			
23	05LNX00103 - LINE EXT 80% GTY		128			
24	05LNX00105 - CNTRCT $ MIN GTY		5,350			
25	05LNX00109 - REF/NREF ADV +		394,435			
26	05LNX00110 - REF/NREF ADV +		5,280			
27	05LNX00114 - TEMP SVC 12MO>		341			
28	05LNX00300 - LINE EXT 80% GTY		125,219			
29	05LNX00310 - LINE EXT		5,276			
30	05LNX00311 - LINE EXT 80% GTY		48,673			
31	05LNX00312 - WY IRG LINE EXT		5,330			
32	05NMT25135 - WY NET MTR, GEN	338	34,212	32	10,563	0.1012
33	05NMT28135 - NET MTR SM GEN	7,853	660,620	22	356,955	0.0841
34	05OALT015N - OUTD AR LGT SR	2,572	359,958	1,580	1,628	0.1400
35	05RCFL0054 - WY REC FIELD L	848	58,801	59	14,373	0.0693
36	09OALT207N - SECURITY AR LG		7			
37	REVENUE_ACCT ADJ		218,710			
38	REVENUE ADJ - DEF NPC		-107,965			
39	INCOME TAX DEFERRAL ADJ		-1,026,277			
40	DSM REVENUE-LARGE		60,511			
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
42	Total Unbilled Rev.(See Instr. 6)	-218,057	-26,093,000	0	0	0.1197
43	TOTAL	55,115,456	4,722,801,747	1,899,813	29,011	0.0857

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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	DSM REVENUE-SMALL		2,868,730			
2	BLUE SKY REV-COMMERCIAL		9,523			
3	UNBILLED REVENUE	28,079	2,173,000			0.0774
4	05GNSV0025 - WY GEN SRVC	29,660	2,909,061	2,403	12,343	0.0981
5	05GNSV0028 - GEN SVC > 15 KW	89,653	7,595,986	387	231,661	0.0847
6	05GNSV025F - GEN SRVC-FL RA	199	24,922	33	6,030	0.1252
7	05LNX00102 - LINE EXT 80% GTY		114,481			
8	05LNX00109 - REF/NREF ADV +		148,631			
9	05LNX00300 - LINE EXT 80% GTY		6,603			
10	05LNX00311 - LINE EXT 80% GTY		6,201			
11	05NMT25135 - WY NET MTR, GEN,	133	10,611	5	26,600	0.0798
12	05NMT28135 - NET MTR SM GEN	434	37,536	2	217,000	0.0865
13	09MONL0213 - WY MTR OUTD	324	18,813	12	27,000	0.0581
14	09OALT207N - SECURITY AR LG	274	57,811	139	1,971	0.2110
15	DSM REVENUE-SMALL		331,835			
16	BLUE SKY REV-COMMERCIAL		605			
17	UNBILLED REVENUE	2,483	199,000			0.0801
18						
19	LESS MULTIPLE BILLINGS			-24,039		
20						
21	TOTAL COMMERCIAL SALES	18,078,160	1,541,492,719	211,800	85,355	0.0853
22						
23	INDUSTRIAL SALES					
24	CALIFORNIA					
25	06GNSV0025 - CA GEN SRVC	564	105,958	85	6,635	0.1879
26	06GNSV0A32 - GEN SRVC-20 KW	2,831	464,244	21	134,810	0.1640
27	06LGSV048T - LRG GEN SERV	48,951	5,201,914	9	5,439,000	0.1063
28	06LGSV0A36 - LRG GEN SRVC-O	5,744	792,492	13	441,846	0.1380
29	REVENUE_ACCT ADJ		-139,541			
30	INCOME TAX DEFERRAL ADJ		-247,337			
31	DSM REVENUE-INDUSTRIAL		87,896			
32	BLUE SKY REV-INDUSTRIAL		282			
33	SOLAR FEED-IN REVENUE		1,283			
34	UNBILLED REVENUE	-1,094	-134,000			0.1225
35						
36	IDAHO					
37	07CFR00001 - MTH FACILITY S		2,217			
38	07CISH0019 - COMM & IND SPA	19	1,810	1	19,000	0.0953
39	07GNSV0006 - GEN SRVC-LRG P	90,195	6,410,789	102	884,265	0.0711
40	07GNSV0009 - GEN SRVC-HI VO	74,941	4,897,655	14	5,352,929	0.0654
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
42	Total Unbilled Rev.(See Instr. 6)	-218,057	-26,093,000	0	0	0.1197
43	TOTAL	55,115,456	4,722,801,747	1,899,813	29,011	0.0857

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1	07GNSV0023 - GEN SRVC-SML P	16,923	1,598,940	312	54,240	0.0945
2	07GNSV006A - GEN SRVC-LG P	3,480	291,387	23	151,304	0.0837
3	07GNSV023A - GEN SRVC-SML P	2,095	216,161	140	14,964	0.1032
4	07GNSV023S - ID TRAFFIC	5	612	1	5,000	0.1224
5	07LNX00108 - ANN COST MTHLY		1,996			
6	07LNX00311 - LINE EXT 80% GTY		635			
7	07OALT007N - SECURITY AR LG	13	4,964	16	813	0.3818
8	07OALT07AN - SECURITY AR LG		134			
9	07SPCL0001	1,524,300	93,971,100	1	1,524,300,000	0.0616
10	07SPCL0002	117,004	6,967,437	1	117,004,000	0.0595
11	REVENUE_ACCT ADJ		19,661			
12	INCOME TAX DEFERRAL ADJ		-2,010,292			
13	DSM REVENUE-INDUSTRIAL		166,988			
14	BLUE SKY REV-INDUSTRIAL		4			
15	UNBILLED REVENUE	11,462	219,000			0.0191
16						
17	OREGON					
18	01COST0023 - OR GEN SRV CST	18,018	1,076,744			0.0598
19	01COST0048 - 01LGSV0048	1,311,580	65,512,880			0.0499
20	01COST023F - OR GEN SRV -	1	65			0.0650
21	01COSTB023 - OR GEN SRV,	119	7,148			0.0601
22	01COSTL030 - OR LRG GEN SRV,	181,008	9,587,167			0.0530
23	01COSTS028 - OR GEN SERV	92,069	5,653,350			0.0614
24	01GNSB0023 - OR GEN SRV, BPA		8,250	12		
25	01GNSB0028 - OR GEN SRV, BPA		7,337	2		
26	01GNSV0023 - OR GEN SRV, < 30		1,011,389	973		
27	01GNSV0028 - OR GEN SRV > 30		3,428,045	437		
28	01GNSV023F - OR GEN SRV - FLAT	2	692	2	1,000	0.3460
29	01GNSV023M - OR GEN SRV		311	1		
30	01GNSV023T - OR GEN SRV, TOU		2,863	3		
31	01GNSV0748 - LG GEN SVC DIR		2,697,222	4		
32	01LGSV0030 - OR LRG GEN SRV, >		6,962,273	129		
33	01LGSV0048 - 1000KW AND OVR		24,377,920	82		
34	01LGSV048M - LRG GEN SRVC 1	70,216	5,210,879	3	23,405,333	0.0742
35	01LNX00102 - LINE EXT 80% GTY		126,733			
36	01LNX00109 - REF/NREF ADV +		85			
37	01LNX00300 - LINE EXT 80%		13,488			
38	01LPRS047M - PART REQ SRVC	2,280	1,140,183	1	2,280,000	0.5001
39	01NMT23135 - OR NET MTR, GEN,		3,437	4		
40	01NMT28135 - OR NET MTR, GEN,		50,298	6		
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
42	Total Unbilled Rev.(See Instr. 6)	-218,057	-26,093,000	0	0	0.1197
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1	01NMT30135 - OR NET MTR, GEN,		40,720	1		
2	01OALT015N - OUTD AR LGT NR	273	39,675	123	2,220	0.1453
3	01OALTB15N - OR OUTD AR LGT	3	505	4	750	0.1683
4	01PTOU0023 - OR GEN SRV, TOU	45	2,846			0.0632
5	01RENW0023 - OR RENW USAGE	46	2,888			0.0628
6	01STDAY028 - OR DAY STD OFF,	668	43,690			0.0654
7	01STDAY048 - 01LGNSV048	533	24,342			0.0457
8	01VIR23136 - OR VOL INC <= 30		973	1		
9	01VIR28136 - OR VOL INC > 30 KW		32,175	2		
10	01VIR30136 -OR VOL INCE > 200		45,503	1		
11	REVENUE_ACCT ADJ		-1,653,457			
12	INCOME TAX DEFERRAL ADJ		-6,558,374			
13	OR GAIN ON SALE OF ASSET		4,010			
14	DSM REVENUE-INDUSTRIAL		936,656			
15	BLUE SKY REV-INDUSTRIAL		305,737	35		
16	SOLAR FEED-IN REVENUE		1,085,788			
17	UNBILLED REVENUE	-7,336	-749,000			0.1021
18						
19	UTAH					
20	08CFR00051 - MTH FAC SRVCHG		18,561			
21	08EFOP0021 - ELEC FURNACE O	1,011	109,981	2	505,500	0.1088
22	08EFOP021M - ELEC FURNACE O	878	138,107	2	439,000	0.1573
23	08GNSV0006 - GEN SRVC-DISTR	635,365	53,397,151	985	645,041	0.0840
24	08GNSV0008 - UT GEN SVC TOU >	972,562	71,411,295	97	10,026,412	0.0734
25	08GNSV0009 - GEN SRVC-HI VO	2,916,563	159,767,222	106	27,514,745	0.0548
26	08GNSV0023 - GEN SRVC-DISTR	52,435	5,144,967	3,185	16,463	0.0981
27	08GNSV006A - GEN SRVC-ENERG	52,270	6,150,226	233	224,335	0.1177
28	08GNSV006B - GEN SRVC-DEM&	3	725			0.2417
29	08GNSV008M - UT GEN SVC TOU >	29,305	2,405,173	4	7,326,250	0.0821
30	08GNSV009A - GEN SRVC HI VO	17,358	1,533,234	7	2,479,714	0.0883
31	08GNSV009M - MANL HIGH VOLT	715,006	37,247,875	10	71,500,600	0.0521
32	08GNSV023F - GEN SRVC FIXED	4	2,767	1	4,000	0.6918
33	08GNSV06AM - MNL ENERGY TOD	242	30,610	2	121,000	0.1265
34	08GNSV06MN - GNSV DIST VOLT	1,119	99,073	24	46,625	0.0885
35	08LNX00002 - MTHLY 80% GTY		681,986			
36	08LNX00014 - 80% MIN MNTHLY		8,035			
37	08LNX00017 - ADV/REF&80%ANN		638			
38	08LNX00300 - LINE EXT 80% PLUS		39,252			
39	08MONL0015 - MTR OUTDONIGHT	13	2,053	6	2,167	0.1579
40	08NMT06135 - UT NET MTR, GEN	2,240	206,122	6	373,333	0.0920
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
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1	08NMT23135 - UT NET MTR, GEN,	177	20,349	16	11,063	0.1150
2	08NMT6A135 - NET MTR GEN SVC	3,894	553,968	13	299,538	0.1423
3	08OALT007N - SECURITY AR LG	1,062	221,654	412	2,578	0.2087
4	08PRSV031M - BKUP MNT&SUPPL	56,836	4,026,685	3	18,945,333	0.0708
5	08SPCL0001	618,434	32,222,232	1	618,434,000	0.0521
6	08SPCL0002	781,605	35,565,034	1	781,605,000	0.0455
7	08SPCL0003	1,260,820	59,292,818	1	1,260,820,000	0.0470
8	08SSLR0006 - GEN SVC SUBSCR	226	21,489	1	226,000	0.0951
9	08SSLR0023 - SM GEN SVC	156	18,428	19	8,211	0.1181
10	08SSLR006A - GEN SVC TOU	12,260	1,077,803	29	422,759	0.0879
11	08TOSS0015 - TRAF & OTHER	21	2,420	11	1,909	0.1152
12	REVENUE_ACCT ADJ		-165,528			
13	REVENUE ADJ - DEF NPC		492,340			
14	DSM REVENUE-INDUSTRIAL		2,594,083			
15	BLUE SKY REV-INDUSTRIAL		64,973	7		
16	SOLAR FEED-IN REVENUE		2,293,588			
17	UNBILLED REVENUE	-145,231	-8,282,000			0.0570
18						
19	WASHINGTON					
20	02GNSB0024 - WA GEN SRVC DO	1,015	110,649	43	23,605	0.1090
21	02GNSB24FP - WA GEN SVC	6	2,545	1	6,000	0.4242
22	02GNSV0024 - WA GEN SRVC	14,977	1,454,615	327	45,801	0.0971
23	02GNSV024F - WA GEN SRVC-FL	33	8,877	4	8,250	0.2690
24	02LGSB0036 - LRG GEN SVC IRG	1,337	174,643	9	148,556	0.1306
25	02LGSV0036 - WA LRG GEN SRV	97,456	8,306,800	96	1,015,167	0.0852
26	02LGSV048T - LRG GEN SRVC 1	598,035	40,172,120	30	19,934,500	0.0672
27	02LNX00103 - LINE EXT 80% GTY		25,144			
28	02OALT015N - WA OUTD AR LGT	96	13,175	37	2,595	0.1372
29	02OALTB15N - WA OUTD AR LGT	27	4,191	14	1,929	0.1552
30	02PRSV47TM - LRG PART REQMT	2,533	399,112	1	2,533,000	0.1576
31	REVENUE_ACCT ADJ		-4,309,285			
32	REVENUE ADJ - DEF NPC		30,048			
33	INCOME TAX DEFERRAL ADJ		-1,601,330			
34	ALT REVENUE PROGRAM ADJ		-169,071			
35	DSM REVENUE-INDUSTRIAL		1,549,619			
36	BLUE SKY REV-INDUSTRIAL		26	2		
37	UNBILLED REVENUE	-29,110	-2,726,000			0.0936
38						
39	WYOMING					
40	05GNSV0025 - WY GEN SRVC	29,408	2,521,060	1,182	24,880	0.0857
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
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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	05GNSV0028 - GEN SVC > 15 KW	256,823	18,799,487	442	581,048	0.0732
2	05GNSV025F - GEN SRVC-FL RA	26	4,283	8	3,250	0.1647
3	05LGSV0046 - WY LRG GEN SRV	1,669,556	109,515,760	57	29,290,456	0.0656
4	05LGSV046M - WY LRG GEN SRV	12,108	854,284	1	12,108,000	0.0706
5	05LGSV048M - TOU>1000KW MAN	297,744	16,723,638	1	297,744,000	0.0562
6	05LGSV048T - LRG GENSRV TIM	1,858,845	103,730,296	11	168,985,909	0.0558
7	05LNX00100 - LINE EXT 60% GTY		23,559			
8	05LNX00102 - LINE EXT 80% GTY		1,152,983			
9	05LNX00105 - CNTRCT $ MIN GTY		44,072			
10	05LNX00109 - REF/NREF ADV +		192,232			
11	05LNX00110 - REF/NREF ADV +		620			
12	05LNX00300 - LINE EXT 80% GTY		81,775			
13	05LNX00311 - LINE EXT 80% GTY		16,552			
14	05OALT015N - OUTD AR LGT SR	69	8,754	38	1,816	0.1269
15	05PRSV033M - PART SERV REQ	1,218,564	80,568,372	9	135,396,000	0.0661
16	REVENUE_ACCT ADJ		950,315			
17	REVENUE ADJ - DEF NPC		-526,440			
18	INCOME TAX DEFERRAL ADJ		-5,004,172			
19	DSM REVENUE-SMALL		646,906			
20	DSM REVENUE-LARGE		1,216,544			
21	BLUE SKY REV-INDUSTRIAL		23			
22	UNBILLED REVENUE	68,710	3,481,000			0.0507
23	05GNSV0025 - WY GEN SRVC	7,341	632,861	284	25,849	0.0862
24	05GNSV0028 - GEN SVC > 15 KW	62,047	4,394,905	73	849,959	0.0708
25	05GNSV028M - GEN SVC > 15 KW	5,343	311,967	3	1,781,000	0.0584
26	05LGSV0046 - WY LRG GEN SRV	21,925	1,524,046	3	7,308,333	0.0695
27	05LGSV048M - TOU>1000KW	152,396	9,145,222	3	50,798,667	0.0600
28	05LGSV048T - LRG GENSRV TIM	1,186,921	72,405,229	12	98,910,083	0.0610
29	05LNX00102 - LINE EXT 80% GTY		446,392			
30	05LNX00109 - REF/NREF ADV +		1,990,518			
31	05PRSV033M - PART SERV REQ	99,178	6,056,620	2	49,589,000	0.0611
32	09OALT207N - SECURITY AR LG	5	879	3	1,667	0.1758
33	DSM REVENUE-SMALL		167,605			
34	DSM REVENUE-LARGE		714,553			
35	BLUE SKY REV-INDUSTRIAL		8			
36	UNBILLED REVENUE	12,030	735,000			0.0611
37						
38	LESS MULTIPLE BILLINGS			-896		
39						
40	TOTAL INDUSTRIAL SALES	19,199,036	1,184,766,800	9,549	2,010,581	0.0617
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
42	Total Unbilled Rev.(See Instr. 6)	-218,057	-26,093,000	0	0	0.1197
43	TOTAL	55,115,456	4,722,801,747	1,899,813	29,011	0.0857

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 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	IRRIGATION SALES					
2	CALIFORNIA					
3	06APSV0020 - AG PMP SRVC	12,678	1,797,144	754	16,814	0.1418
4	06APSV0115 - CA AGRI PUMP TOU	178	21,780	2	89,000	0.1224
5	06APSV020L - AG PMP SRVC-NO	50,474	7,335,742	596	84,688	0.1453
6	06APSV115L - CA AGRI PUMP TOU	566	81,893	9	62,889	0.1447
7	06LGSV048T - LRG GEN SERV	829	113,795	1	829,000	0.1373
8	06LNX00103 - LINE EXT 80% GTY		4,515			
9	06LNX00109 - REF/NREF ADV +		649			
10	06LNX00110 - REF/NREF ADV +		41,731			
11	06LNX00310 - IRG, 80% AN MIN +		4,672			
12	06LNX00312 - CA IRG LINE EXT		25,324			
13	06NML20135 - AGRI PUMP-NET	1,402	249,544	18	77,889	0.1780
14	06NMT20135 - AGRI PUMP-NET		1,460	1		
15	06USBR0020 - KLAM IRG ONPRJ	4,376	732,601	268	16,328	0.1674
16	06USBR0115 - CA AGR PMP TOU	26	4,275	2	13,000	0.1644
17	06USBR020L - KLAM IRG ONPRJ	16,228	2,667,561	345	47,038	0.1644
18	06USBR115L - CA AGR PMP TOU	607	88,584	9	67,444	0.1459
19	INCOME TAX DEFERRAL ADJ		-341,459			
20	REVENUE_ACCT ADJ		-343,275			
21	DSM REVENUE-IRRIGATION		271,088			
22	BLUE SKY REV-IRRIGATION		40			
23	SOLAR FEED-IN REVENUE		2,976			
24	UNBILLED REVENUE	1,045	59,000			0.0565
25						
26	IDAHO					
27	07APSA010L - IRG & PUMP LG	366,764	33,777,366	2,521	145,484	0.0921
28	07APSA010S - IRG & PUMP SM	6,103	647,530	340	17,950	0.1061
29	07APSAL10X - IRG & PUMP - LG	186,927	17,447,403	1,662	112,471	0.0933
30	07APSAS10X - IRG & PUMP - SM	6,719	745,258	491	13,684	0.1109
31	07APSN010L - ID LG IRR & PUMP	5,810	531,815	34	170,882	0.0915
32	07APSN010S - IRR, SM 3 PH	17	2,719	4	4,250	0.1599
33	07APSNS10X - IRR, SM, 3 PHASE	205	24,401	15	13,667	0.1190
34	07APSV006A - LRG POWER OPT	232	21,984	1	232,000	0.0948
35	07APSV023A - SM POWER OPT	98	10,027	4	24,500	0.1023
36	07APSVCNLL - LRG LOAD CANAL	12,882	1,075,465	37	348,162	0.0835
37	07APSVCNLS - SM LOAD CANAL	27	4,504	11	2,455	0.1668
38	07GNSV023A - GEN SRVC-SM	128	11,537	1	128,000	0.0901
39	07LNX00015 - ANN 80% GTY		72,426			
40	07LNX00035 - ADV 80% MO GTY		1,847			
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
42	Total Unbilled Rev.(See Instr. 6)	-218,057	-26,093,000	0	0	0.1197
43	TOTAL	55,115,456	4,722,801,747	1,899,813	29,011	0.0857

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SALES OF ELECTRICITY BY RATE SCHEDULES

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Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	07LNX00040 - ADV+REFCHG+80%		132,200			
2	07LNX00312 - ID LINE EXT		61,782			
3	REVENUE_ACCT ADJ		-170,806			
4	INCOME TAX DEFERRAL ADJ		-617,683			
5	DSM REVENUE-IRRIGATION		1,428,635			
6	BLUE SKY REV-IRRIGATION		23			
7	UNBILLED REVENUE	82	4,000			0.0488
8						
9	OREGON					
10	01APSV0041 - AG PMP SRVC BP		1,476,626	2,647		
11	01APSV0215 - OR IRR TOU PILOT		19,707	11		
12	01APSV041L - OR PUMP SRV		2,383,552	753		
13	01APSV041T - AGR PUMP		30,766	55		
14	01APSV041X - AG PMP SRVC		1,173,982	2,257		
15	01APSV41XL - OR PUMP SRV no		1,841,058	423		
16	01COST0041 - AG PMP	137,140	8,246,356			0.0601
17	01COST0048 - 01LGSV0048	114,827	5,796,631			0.0505
18	01COST0215 - OR TOU PILOT	4,067	182,953			0.0450
19	01CSTUSB41 - USBR IRR	65,405	3,927,323			0.0600
20	01GNSV023T - OR GEN SRV, TOU		453	1		
21	01HABIT041 - 01APSV0041 AG	9	543			0.0603
22	01LGSB0048 - LG GEN SVC >		1,024,400	3		
23	01LGSV0048 - 1000KW AND OVR		1,345,489	3		
24	01LNX00103 - LINE EXT 80% GTY		29,727			
25	01LNX00109 - REF/NREF ADV +		76			
26	01LNX00110 - REF/NREF ADV +		142,944			
27	01LNX00310 - LINE EXT		13,461			
28	01LNX00312 - OR IRG LINE EXT		31,417			
29	01NMT41135 - NETMTR AG PMP		26,821	23		
30	01NMU41135 - OR NET MTR -		29,915	12		
31	01PTOU0023 - OR GEN SRV, TOU	7	449			0.0641
32	01PTOU0041 - 01APSV0041 AG	610	36,338			0.0596
33	01RENEW041 - 01APSV0041 AG	158	9,691			0.0613
34	01STDAY041 - DAILY STANDARD	159	11,087			0.0697
35	01USBR0215 - OR IRG TOU PILOT		147,546	76		
36	01USBRGV41 - IRG TOU W/O BPA		52,187	9		
37	01USBROF41 - KLAMATH BASIN		1,250,657	479		
38	01USBRON41 - KLAMATH BASIN		1,710,245	1,115		
39	01VIR41136 - OR VOLINC-AGRI		56,256	26		
40	01VRU41136 - OR VOL INCE USB		354,847	104		
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
42	Total Unbilled Rev.(See Instr. 6)	-218,057	-26,093,000	0	0	0.1197
43	TOTAL	55,115,456	4,722,801,747	1,899,813	29,011	0.0857

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1	01VRU41215 - OR VOL INC USB		37,912	6		
2	REVENUE_ACCT ADJ		-83,854			
3	INCOME TAX DEFERRAL ADJ		-1,083,348			
4	OR GAIN ON SALE OF ASSET		128			
5	DSM REVENUE-IRRIGATION		658,311			
6	BLUE SKY REV-IRRIGATION		269			
7	SOLAR FEED-IN REVENUE		47,272			
8	UNBILLED REVENUE	17,394	1,822,000			0.1047
9						
10	UTAH					
11	08APSV0010 - IRR & SOIL DRA	231,433	16,482,207	3,045	76,004	0.0712
12	08APSV10NS - IRR LG SOIL DRAIN	34,913	2,386,353	265	131,747	0.0684
13	08LNX00004 - ANN 80% GTY		7,572			
14	08LNX00014 - 80% MIN MNTHLY		6,198			
15	08LNX00017 - ADV/REF&80%ANN		176,274			
16	08LNX00310 - IRR, 80% ANNUAL		24,588			
17	08LNX00311 - LINE EXT 80% GTY		496			
18	08LNX00312 - UT IRG LINE EXT		19,977			
19	08NMT010NS - IRR & SOIL DRAIN	329	29,331	3	109,667	0.0892
20	08NMT10135 - UT IRR_SOIL DRNG	7,800	567,004	45	173,333	0.0727
21	REVENUE_ACCT ADJ		-13,852			
22	REVENUE ADJ - DEF NPC		17,440			
23	DSM REVENUE-IRRIGATION		73,003			
24	SOLAR FEED-IN REVENUE		64,505			
25	UNBILLED REVENUE	-495	-37,000			0.0747
26						
27	WASHINGTON					
28	02APSV0040 - WA AG PMP SRVC	106,590	10,101,606	2,942	36,230	0.0948
29	02APSV040X - WA AG PMP SRVC	59,745	5,729,113	2,217	26,949	0.0959
30	02LNX00102 - LINE EXT 80% GTY		2,711			
31	02LNX00103 - LINE EXT 80% GTY		7,567			
32	02LNX00105 - CNTRCT $ MIN GTY		76			
33	02LNX00109 - REF/NREF ADV +		2,601			
34	02LNX00110 - REF/NREF ADV +		173,417			
35	02LNX00310 - IRG, 80% ANN MIN +		3,599			
36	02LNX00312 - WA IRG LINE EXT		29,402			
37	02NMT40135 - WA NET MTR-IRG	226	22,370	9	25,111	0.0990
38	02NMX40135 - WA NET MTR-IRG	2	837	2	1,000	0.4185
39	REVENUE_ACCT ADJ		-1,176,625			
40	REVENUE ADJ - DEF NPC		5,644			
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
42	Total Unbilled Rev.(See Instr. 6)	-218,057	-26,093,000	0	0	0.1197
43	TOTAL	55,115,456	4,722,801,747	1,899,813	29,011	0.0857

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1	INCOME TAX DEFERRAL ADJ		-279,766			
2	ALT REVENUE PROGRAM ADJ		-315,686			
3	DSM REVENUE-IRRIGATION		501,827			
4	BLUE SKY REV-IRRIGATION		234			
5	UNBILLED REVENUE	-470	-32,000			0.0681
6						
7	WYOMING					
8	05APS00040 - AG PUMP SVC	18,593	1,578,611	702	26,486	0.0849
9	05APSNS040 - AG PUMP SVC	1,335	105,733	21	63,571	0.0792
10	05LNX00103 - LINE EXT 80% GTY		2,326			
11	05LNX00109 - REF/NREF ADV +		325			
12	05LNX00110 - REF/NREF ADV +		36,949			
13	05LNX00310 - LINE EXT		554			
14	05LNX00312 - WY IRG LINE EXT		4,886			
15	09APSNS210 - IRR & SOIL DRA	9	1,459	1	9,000	0.1621
16	REVENUE_ACCT ADJ		3,385			
17	REVENUE ADJ - DEF NPC		-1,989			
18	INCOME TAX DEFERRAL ADJ		-18,910			
19	DSM REVENUE-IRRIGATION		55,832			
20	BLUE SKY REV-IRRIGATION		20			
21	UNBILLED REVENUE	17	1,000			0.0588
22	05APS00040 - AG PUMP SVC	132	10,928	4	33,000	0.0828
23	05LNX00110 - REF/NREF ADV +		12,876			
24	05LNX00310 - LINE EXT		1,746			
25	09APSNS210 - IRR & SOIL DRA	468	41,853	3	156,000	0.0894
26	09APSV0210 - IRR & SOIL DRA	6,056	468,570	94	64,426	0.0774
27	DSM REVENUE-IRRIGATION		17,201			
28	UNBILLED REVENUE	3				
29						
30	LESS MULTIPLE BILLINGS			-845		
31						
32	TOTAL IRRIGATION SALES	1,480,865	137,688,644	23,637	62,650	0.0930
33						
34	PUBLIC STREET & HWY LIGHTING					
35	CALIFORNIA					
36	06CUSL053E - SPECIAL CUST O	1,122	198,251	105	10,686	0.1767
37	06CUSL058F - CUST OWND STR	52	10,334	20	2,600	0.1987
38	06OALT015N - OUTD AR LGT SR		243	1		
39	06SLCO0051 - COMPANY OWNED	673	216,292	77	8,740	0.3214
40	REVENUE_ACCT ADJ		-12,144			
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
42	Total Unbilled Rev.(See Instr. 6)	-218,057	-26,093,000	0	0	0.1197
43	TOTAL	55,115,456	4,722,801,747	1,899,813	29,011	0.0857

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1	INCOME TAX DEFERRAL ADJ		-8,464			
2	DSM REVENUE-PUB ST & HWY LT		10,302			
3	SOLAR FEED-IN REVENUE		89			
4	UNBILLED REVENUE	-339	-74,000			0.2183
5						
6	IDAHO					
7	07GNSV023S - ID TRAFFIC	146	17,869	24	6,083	0.1224
8	07SLCO0011 - STR LGT CO-OWN	143	67,061	65	2,200	0.4690
9	07SLCU012E - ENGY STR LGT	396	43,527	39	10,154	0.1099
10	07SLCU012F - FULL MNT STR LGT	1,815	361,112	186	9,758	0.1990
11	07SLCU012P - PART MNT STR LGT	194	28,072	16	12,125	0.1447
12	REVENUE_ACCT ADJ		-2,559			
13	INCOME TAX DEFERRAL ADJ		-3,114			
14	DSM REVENUE-PUB ST & HWY LT		13,726			
15	UNBILLED REVENUE	-49	-9,000			0.1837
16						
17	OREGON					
18	01COSL0052 - STR LGT SRVC C	370	57,083	35	10,571	0.1543
19	01COST023F - OR GEN SRV	668	42,335			0.0634
20	01CUSL0053 - CUS-OWNED MTRD	522	39,100	73	7,151	0.0749
21	01CUSL053E - STR LGT SVC	11,324	848,032	221	51,240	0.0749
22	01CUSL053F - STR LGT SRVC C	116	11,244	9	12,889	0.0969
23	01GNSV023F - OR GEN SRV - FLAT		120,589	39		
24	01HPSV0051 - HI PRESSURE SO	19,014	4,045,615	754	25,218	0.2128
25	01LEDSL051 - OR LED PILOT	533	186,651	75	7,107	0.3502
26	01MVSL0050 - MERC VAPSTR LG	7,329	979,115	231	31,727	0.1336
27	01OALT015N - OUTD AR LGT NR	33	5,979	15	2,200	0.1812
28	01OALTB15N - OR OUTD AR LGT	5	791	3	1,667	0.1582
29	REVENUE_ACCT ADJ		-15,884			
30	INCOME TAX DEFERRAL ADJ		-142,291			
31	OR GAIN ON SALE OF ASSET		542			
32	DSM REVENUE-PUB ST & HWY LT		182,322			
33	SOLAR FEED-IN REVENUE		10,268			
34	UNBILLED REVENUE	-3,280	-512,000			0.1561
35						
36	UTAH					
37	08CFR00012 - STR LGTS (CONV		54			
38	08CFR00051 - MTH FAC SRVCHG		4,529			
39	08CFR00062 - STREET LIGHTS		79			
40	08MONL0015 - MTR OUTDONIGHT	904	73,246	92	9,826	0.0810
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
42	Total Unbilled Rev.(See Instr. 6)	-218,057	-26,093,000	0	0	0.1197
43	TOTAL	55,115,456	4,722,801,747	1,899,813	29,011	0.0857

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1	08OALT007N - SECURITY AR LG	161	42,234	67	2,403	0.2623
2	08SLCO0011 - STR LGT CO-OWN	13,640	4,104,796	708	19,266	0.3009
3	08SLCU012E - DECOR CUST-OWN	43,694	2,788,215	941	46,434	0.0638
4	08SLCU012F - STR LGT CUST-O	1,031	135,848	71	14,521	0.1318
5	08SLCU012P - STR LGT CUST-O	3,114	383,680	173	18,000	0.1232
6	08TOSS0015 -TRAF & OTHER	3,157	355,687	1,497	2,109	0.1127
7	08TOSS015F - TRAFFIC SIG NM	1,155	101,823	121	9,545	0.0882
8	REVENUE_ACCT ADJ		-19,171			
9	REVENUE ADJ - DEF NPC		5,659			
10	DSM REVENUE-PUB ST & HWY LT		23,785			
11	SOLAR FEED-IN REVENUE		20,667			
12	UNBILLED REVENUE	1,307	159,000			0.1217
13						
14	WASHINGTON					
15	02CFR00012 - STR LGTS		91			
16	02COSL0052 - WA STR LGT SRV	143	31,097	14	10,214	0.2175
17	02CUSL053F - WA STR LGT SRV	2,961	224,071	120	24,675	0.0757
18	02CUSL053M - WA STR LGT SRV	742	55,574	111	6,685	0.0749
19	02MVSL0057 - WA MERC VAPSTR	1,594	212,103	40	39,850	0.1331
20	02SLCO0051 - WA COMPANY	3,840	828,618	211	18,199	0.2158
21	REVENUE_ACCT ADJ		-66,463			
22	INCOME TAX DEFERRAL ADJ		-23,178			
23	DSM REVENUE-PUB ST & HWY LT		24,566			
24	UNBILLED REVENUE	-692	-100,000			0.1445
25						
26	WYOMING					
27	05COSL0057 - CO-OWND STR LG	243	48,922	15	16,200	0.2013
28	05CUSL0058 - CUST OWND STR	58	3,284	11	5,273	0.0566
29	05CUSL0E58 - WY CUST OWNED	1,090	61,580	33	33,030	0.0565
30	05CUSL0M58 - CUST OWNED ST	44	3,037	3	14,667	0.0690
31	05HPSV0051 - HI PRESSURE SO	5,778	1,087,029	186	31,065	0.1881
32	05MVS00053 - MERCURY VAPOR	3,609	416,745	229	15,760	0.1155
33	05OALT015N - OUTD AR LGT SR	38	4,286	3	12,667	0.1128
34	REVENUE_ACCT ADJ		774			
35	REVENUE ADJ - DEF NPC		-955			
36	INCOME TAX DEFERRAL ADJ		-9,082			
37	DSM REVENUE-PUB ST & HWY LT		48,564			
38	UNBILLED REVENUE	59	6,000			0.1017
39	09MONL0213 - WY MTR OUTDOOR	27	2,654	1	27,000	0.0983
40	09SLCO0211 - STR LGT CO-OWN	1,495	334,768	50	29,900	0.2239
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
42	Total Unbilled Rev.(See Instr. 6)	-218,057	-26,093,000	0	0	0.1197
43	TOTAL	55,115,456	4,722,801,747	1,899,813	29,011	0.0857

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1	09SLCUP212 - CUST OWNED ST	34	4,932	5	6,800	0.1451
2	09TOSS0213 - WY TRAFFIC &	47	2,352	15	3,133	0.0500
3	DSM REVENUE-PUB ST & HWY LT		10,863			
4	UNBILLED REVENUE	218	46,000			0.2110
5						
6	LESS MULTIPLE BILLINGS			-3,204		
7						
8	TOTAL PUBLIC STREET & HWY LT	130,278	18,155,451	3,501	37,212	0.1394
9						
10	FORFEITED DISCOUNTS					
11	CALIFORNIA					
12	06LPAY0300 - RES-LATEFEE		219,185			
13	06LPAY0300 - COM-LATEFEE		52,829			
14	06LPAY0300 - IND-LATEFEE		56,433			
15	06LPAY0300 - OTHER-LATEFEE		411			
16						
17	IDAHO					
18	07LPAY0300 - RES-LATEFEE		217,156			
19	07LPAY0300 - COM-LATEFEE		32,011			
20	07LPAY0300 - IND-LATEFEE		141,276			
21	07LPAY0300 - OTHER-LATEFEE		1,925			
22						
23	OREGON					
24	01LPAY0300 - RES-LATEFEE		3,321,828			
25	01LPAY0300 - COM-LATEFEE		809,683			
26	01LPAY0300 - IND-LATEFEE		235,865			
27	01LPAY0300 - OTHER-LATEFEE		37,264			
28						
29	UTAH					
30	08LPAY0300 - RES-LATEFEE		2,336,882			
31	08LPAY0300 - COM-LATEFEE		681,384			
32	08LPAY0300 - IND-LATEFEE		250,814			
33	08LPAY0300 - OTHER-LATEFEE		95,874			
34	OTHER		1,486			
35						
36	WASHINGTON					
37	02LPAY0300 - RES-LATEFEE		547,035			
38	02LPAY0300 - COM-LATEFEE		132,139			
39	02LPAY0300 - IND-LATEFEE		28,491			
40	02LPAY0300 - OTHER-LATEFEE		3,794			
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
42	Total Unbilled Rev.(See Instr. 6)	-218,057	-26,093,000	0	0	0.1197
43	TOTAL	55,115,456	4,722,801,747	1,899,813	29,011	0.0857

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1						
2	WYOMING					
3	05LPAY0300 - RES-LATEFEE		400,469			
4	05LPAY0300 - COM-LATEFEE		102,996			
5	05LPAY0300 - IND-LATEFEE		41,342			
6	05LPAY0300 - OTHER-LATEFEE		2,208			
7	05LPAY0300 - RES-LATEFEE		44,893			
8	05LPAY0300 - COM-LATEFEE		8,648			
9	05LPAY0300 - IND-LATEFEE		6,877			
10	05LPAY0300 - OTHER-LATEFEE		1			
11						
12	TOTAL FORFEITED DISCOUNTS		9,811,199			
13						
14	MISC SERVICE REVENUE					
15	CALIFORNIA					
16	06CFR00003 - MTH MAINTENANC		1,454			
17	06CONN0300 - CA RECONNECTIO		29,775			
18	06FCBUYOUT		9,581			
19	06NMT20135 - AGRI PUMP-NET		10			
20	06NSMTR300 - NON-STND MTR		2,745			
21	06RCHK0300 - CA RET CHK CHR		11,988			
22	06TAMP0300 - CA TAMP & UNAU		1,500			
23	06TEMP0300 - CA TEMP SRVC C		1,700			
24	06TRBL0300 - CA TROUBLE CAL		60			
25	06XMTRTAMP - TAMP		399			
26	OTHER		25			
27						
28	IDAHO					
29	07CFR00001 - MTH FAC SRVCHG		1,451			
30	07CONN0300 - ID RECONNECTIO		15,265			
31	07RCHK0300 - ID RET CHK CHR		32,540			
32	07TAMP0300		600			
33	07TEMP0014 - TEMP SRVC CONN		34,000			
34	07XMTRTAMP - TAMP		142			
35	OTHER		287			
36						
37	OREGON					
38	01ADMINFEE - SCH 272 ANN		23,748			
39	01APSV0041 - AG PMP SRVC BP		180			
40	01APSV041X - AG PMP SRVC		72			
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
42	Total Unbilled Rev.(See Instr. 6)	-218,057	-26,093,000	0	0	0.1197
43	TOTAL	55,115,456	4,722,801,747	1,899,813	29,011	0.0857

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1	01CFR00001 - MTH FACILITY		96,028			
2	01CFR00003 - MTH MAINTENANC		17,804			
3	01CFR00004 - EMRGNCY ST&BY		25,656			
4	01CFR00005 - INTERMTNT SRVC		37,100			
5	01CFR00013 - MTH MISC CHRG		51,677			
6	01CGENAFOR - CUST GEN APP		5,796			
7	01CONN0300 - RECONNECTION		547,545			
8	01CONTSERV - OR 3RD PTY		23,011			
9	01ESSC0600 - ESS CHG		900			
10	01FCBUYOUT - FAC CHG BUYOUT		256,672			
11	01GNSB0023 - OR GEN SRV, BPA,		1,877			
12	01GNSV0023 - OR GEN SRV, < 30		3,562			
13	01GNSV0028 - OR GEN SRV > 30		108			
14	01MTRVR300 - METR VERIF FEE		40			
15	01NETMT135 - NET METERING		2,844			
16	01NMT28135 - OR NET MTR, GEN,		72			
17	01NSMTR300 - OR STD METER		14,703			
18	01RCHK0300 - RET CHECK		296,100			
19	01RESD0004 - RES SRVC		135,181			
20	01RESD004T - RES TIME OPT		468			
21	01RGNSB023 - SM GENL SVC-RES		2,484			
22	01TAMP0300 - TAMP & UNAUTH		10,650			
23	01TEMP0300 - TEMP SRVC CHRG		192,055			
24	01USBRON41 - KLA BASIN IRG ON		216			
25	01VIR04136 - OR RES VOL INC		324			
26	01XMTRTAMP - TAMP- UNAUTH		1,787			
27	01XTHEFREV - THEFT OF SVCS		53			
28	OTHER		-10,154			
29						
30	UTAH					
31	08CFR00051 - MTH FAC SRVCHG		84,942			
32	08CFR00052 - ANN FAC SVCCHG		424			
33	08CFR00053 - MTHLY MAINTFEE		13,374			
34	08CFR00054 - NRES EMERGENCY		4,976			
35	08CFR00063 - MTH MISC CHARG		2,358			
36	08CFR00064 - ANN MISC CHARG		6,660			
37	08CGENFEEN - NRES CSTMR GEN		7,756			
38	08CGENFEER - RES CSTMR GEN		240,842			
39	08CONN0300 - RECON & DISCON		226,130			
40	08CONTSERV - 3RD PARTY O/S		93,000			
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
42	Total Unbilled Rev.(See Instr. 6)	-218,057	-26,093,000	0	0	0.1197
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1	08FCBUYOUT - FAC CHG BUYOUT		1,042,420			
2	08NCON0300 - UT FEE NRES RE		3,775			
3	08NETMT135 - NET MTR		264			
4	08NSMTR300 - UT NON		849			
5	08RCHK0300 - UT RET CHK CHR		511,560			
6	08RCON0001 - CONNECT FEE		1,806,090			
7	08RESD0001 - RES SRVC		4,759			
8	08SOLRXFEE - SUBSCRI SOLAR		17,550			
9	08SSLR0001 - RES SUBSCRB		264			
10	08TAMP0300 - TAMP&UNAU		3,825			
11	08TEMP0014 - TEMP SRVC CONN		695,730			
12	08VISIT300 - UT VISIT SRV CALL		24,055			
13	08XMTRTAMP - TAMP		830			
14	ENERGY FINANSER NEW COM		1,320			
15	OTHER		-960,784			
16						
17	WASHINGTON					
18	02CFR00003 - MTH MAINTENANC		1,320			
19	02CFR00004 - EMRGNCY ST&BY		5,892			
20	02CFR00005 - INTERMTNT SRVC		4,303			
21	02CGENAMWA - CUST GEN APP &		32,450			
22	02CONN0300 - WA RECONNECTIO		51,870			
23	02FCBUYOUT - FAC CHG BUYOUT		6,139			
24	02NSMTR300 - WA STD METER		480			
25	02RCHK0300 - WA RET CHK CHR		59,340			
26	02RESD0016 - WA RES SRVC		560			
27	02TAMP0300 - WA TAMP & UNAU		1,800			
28	02TEMP0300 - WA TEMP SRVC C		26,920			
29	02XMTRTAMP - TAMP		677			
30	OTHER		9,109			
31						
32	WYOMING					
33	05CFR00003 - MTH MAINTENANC		1,768			
34	05CFR00004 - EMRGNCY ST&BY		18,280			
35	05CFR00005 - INTERMTNT SRVC		10,071			
36	05CFR00013 - MTH MISC CHRG		3,186			
37	05CONN0300 - WY RECONNECTIO		65,165			
38	05FCBUYOUT - FAC CHG BUYOUT		16,460			
39	05RCHK0300 - WY RET CHK CHR		80,760			
40	05RESD0002 - WY RES SRVC		1,188			
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
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1	05TAMP0300		450			
2	05TEMP0300 - WY TEMP SRVC C		38,590			
3	05XMTRTAMP - TAMP		53			
4	09CFR00005 - INTERMTNT SRVC		339			
5	OTHER		-480			
6	05CONN0300 - WY RECONNECTIO		7,518			
7	05RCHK0300 - WY RET CHK CHR		8,310			
8	05TAMP0300		75			
9	05TEMP0300 - WY TEMP SRVC C		340			
10	09CFR00001 - MTH FAC SRVCHG		5,001			
11	09CFR00014 - YR MISC CHRG		3			
12						
13	TOTAL MISC SERVICE REVENUE		6,172,987			
14						
15	SALES OF WATER & WATER PWR					
16	UTAH					
17	WATER & WATER PWR SALES		54,615			
18						
19	TOTAL SALES OF WATER & WTR		54,615			
20						
21	RENT FROM ELEC PROPERTIES					
22	CALIFORNIA					
23	06CFR00006 - MTH RNTAL CHRG		1,710			
24	RENT REVENUE-HYDRO		1,500			
25	RENT REVENUE-SUBLEASES		19,200			
26	JOINT USE		533,047			
27						
28	IDAHO					
29	07CFR00009 - YR LSE CHRG-EQ		777			
30	07INVCHG00 - INVEST MNT CHG		151			
31	07POLE0075 - STEEL POLES US		262			
32	RENT REVENUE-GENERAL		492			
33	RENT REVENUE-HYDRO		60,380			
34	RENT REVENUE-TRANSMISSION		14,650			
35	RENT REVENUE-SUBLEASES		2,216			
36	JOINT USE		167,360			
37						
38	OREGON					
39	01CFR00006 - MTH RNTAL CHRG		841,229			
40	RENTS - COMMON		722,958			
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
42	Total Unbilled Rev.(See Instr. 6)	-218,057	-26,093,000	0	0	0.1197
43	TOTAL	55,115,456	4,722,801,747	1,899,813	29,011	0.0857

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RENT REVENUE-DISTRIBUTION		76,904			
2	RENT REVENUE-GENERAL		68,306			
3	RENT REVENUE-HYDRO		26,758			
4	RENT REVENUE-TRANSMISSION		325,808			
5	RENT REVENUE-SUBLEASES		22,030			
6	MCI FOGWIRE REVENUE		3,347,401			
7	JOINT USE		2,801,948			
8						
9	UTAH					
10	08CFR00056 - MTH EQUIP RENT		33			
11	08CFR00058 - MTH EQUIP LEAS		550,016			
12	08INVCHG0N - INVEST MNT CHG		4,007			
13	08INVCHG0R - INVEST MNT CHG		222			
14	08POLE0075 - STEEL POLES US		51,881			
15	RENTS - NON COMMON		3,698			
16	RENT REVENUE-DISTRIBUTION		757,544			
17	RENT REVENUE-GENERAL		19,635			
18	RENT REVENUE-HYDRO		86,705			
19	RENT REVENUE-STEAM		127,585			
20	RENT REVENUE-TRANSMISSION		1,291,880			
21	RENT REVENUE-SUBLEASES		495,802			
22	JOINT USE		2,981,082			
23						
24	WASHINGTON					
25	02CFR00001 - MTH FACILITY		2,104			
26	02CFR00006 - MTH RNTAL CHRG		9,073			
27	RENT REVENUE-DISTRIBUTION		21,037			
28	RENT REVENUE-GENERAL		45,986			
29	RENT REVENUE-HYDRO		357,959			
30	RENT REVENUE-TRANSMISSION		24,784			
31	JOINT USE		772,329			
32						
33	WYOMING					
34	05CFR00001 - MTH FACILITY		11,524			
35	05CFR00006 - MTH RNTAL CHRG		2,482			
36	RENTS - NON COMMON		13,200			
37	RENT REVENUE-DISTRIBUTION		150			
38	RENT REVENUE-GENERAL		75,009			
39	RENT REVENUE-HYDRO		21,521			
40	RENT REVENUE-STEAM		49,268			
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
42	Total Unbilled Rev.(See Instr. 6)	-218,057	-26,093,000	0	0	0.1197
43	TOTAL	55,115,456	4,722,801,747	1,899,813	29,011	0.0857

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 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RENT REVENUE-TRANSMISSION		275			
2	RENT REVENUE-SUBLEASES		42,009			
3	JOINT USE		344,254			
4	09POLE0075 - STEEL POLES US		18,313			
5	RENT REVENUE-STEAM		28,311			
6	OTHER		2,190			
7						
8	TOTAL RENT FROM ELEC		17,246,955			
9						
10	OTHER ELECTRIC REVENUE					
11	ENERGY EXCHANGE CREDITS		453,590			
12	M&S INVENTORY REVENUE		4,006,244			
13	RENEWABLE ENERGY CREDITS		3,300,207			
14	WIND BASED ANCILLARY SVC		11,169,083			
15	MISC OTHER REVENUE		11,376			
16						
17	CALIFORNIA					
18	3RD PARTY TRANS O&M		40,590			
19	CA GHG ALLOW REV AMORT		9,591,652			
20	FISH, WILDLIFE, RECR		9,362			
21						
22	OREGON					
23	3RD PARTY TRANS O&M		167,071			
24	EIM REVENUE		14,572			
25	FERC TRANSMISSION REFUND		-4,129,687			
26	OTHER ELEC (EXLUDE		3,318,126			
27						
28	UTAH					
29	3RD PARTY TRANS O&M		157,176			
30	ELEC INCOME-OTHER		45,665			
31	FISH, WILDLIFE, RECR		3,060			
32	FLYASH SALES		1,936,159			
33						
34	WASHINGTON					
35	FISH, WILDLIFE, RECR		11,010			
36	TIMBER SALES - UTILITY		506,102			
37	WASH COLSTRIP 3		-52,188			
38						
39	WYOMING					
40	3RD PARTY TRANS O&M		68,037			
41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
42	Total Unbilled Rev.(See Instr. 6)	-218,057	-26,093,000	0	0	0.1197
43	TOTAL	55,115,456	4,722,801,747	1,899,813	29,011	0.0857

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 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	FLYASH SALES		2,322,071			
2	WY REG RECOVERY FEE		225,999			
3						
4	TOTAL OTHER ELEC REVENUE		33,175,277			
5						
6						
7						
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15						
16						
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41	TOTAL Billed	55,333,513	4,748,894,747	1,899,813	29,126	0.0858
42	Total Unbilled Rev.(See Instr. 6)	-218,057	-26,093,000	0	0	0.1197
43	TOTAL	55,115,456	4,722,801,747	1,899,813	29,011	0.0857

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	34	35	33
5	Navajo Tribal Util. Auth. (Mexican Hat)	RQ	T-6	0	0	0
6	Navajo Tribal Util. Auth. (Red Mesa)	RQ	T-6	2	2	1
7	Accrual	RQ	NA	NA	NA	NA
8						
9	Non-Requirement Sales:					
10	Arizona Electric Power Cooperative, Inc	SF	T-12	NA	NA	NA
11	Arizona Public Service Company	SF	T-12	NA	NA	NA
12	Arizona Public Service Company	SF	WSPP-Q	NA	NA	NA
13	Avangrid Renewables, LLC	SF	T-12	NA	NA	NA
14	Avangrid Renewables, LLC	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 ($) (h)	REVENUE: Energy Charges ($) (i)	REVENUE: Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
6,033	105,715	107,290		213,005	2
3,568	70,049	63,055		133,104	3
287,015	5,605,229	9,312,805	-1,114,781	13,803,253	4
865	16,690	15,061		31,751	5
9,410	144,584	163,924		308,508	6
1,422			36,708	36,708	7
					8
					9
158,207		4,296,519		4,296,519	10
24,062		832,411		832,411	11
1,600		43,600		43,600	12
1,255,520		36,948,615		36,948,615	13
16			856	856	14
308,313	5,942,267	9,662,135	-1,078,073	14,526,329	
8,001,159	7,490,743	463,953,015	-231,755,357	239,688,401	
8,309,472	**13,433,010**	**473,615,150**	**-232,833,430**	**254,214,730**	

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 2018/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	Basin Electric Power Cooperative, Inc.	SF	T-12	NA	NA	NA
4	Black Hills Power, Inc.	AD	441	NA	NA	NA
5	Black Hills Power, Inc.	LF	441	50	50	45
6	Black Hills Power, Inc.	SF	T-12	NA	NA	NA
7	Black Hills Power, Inc.	SF	WSPP-Q	NA	NA	NA
8	Bonneville Power Administration	AD	T-12	NA	NA	NA
9	Bonneville Power Administration	LU	T-12	NA	NA	NA
10	Bonneville Power Administration	SF	T-12	NA	NA	NA
11	Bonneville Power Administration	SF	T-13	NA	NA	NA
12	Bonneville Power Administration	SF	WSPP-Q	NA	NA	NA
13	BP Energy Company	AD	T-12	NA	NA	NA
14	BP Energy Company	SF	T-12	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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.
72,595		1,704,350		1,704,350	1
17			481	481	2
20,146		629,471		629,471	3
			54,609	54,609	4
289,593	7,490,743	6,250,247		13,740,990	5
105,792		2,664,278		2,664,278	6
450		11,300		11,300	7
-2			137,480	137,480	8
40,029		2,655,524		2,655,524	9
81,651		2,543,009		2,543,009	10
156			2,563	2,563	11
66,173		2,011,607		2,011,607	12
525			19,756	19,756	13
439,781		12,630,744		12,630,744	14
308,313	5,942,267	9,662,135	-1,078,073	14,526,329	
8,001,159	7,490,743	463,953,015	-231,755,357	239,688,401	
8,309,472	**13,433,010**	**473,615,150**	**-232,833,430**	**254,214,730**	

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 2018/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.
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LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	British Columbia Hydro and Power	SF	T-13	NA	NA	NA
2	Brookfield Energy Marketing LP	SF	T-12	NA	NA	NA
3	California Independent System Operator	AD	T-12	NA	NA	NA
4	California Independent System Operator	SF	T-12	NA	NA	NA
5	Calpine Energy Services, L.P.	SF	T-12	NA	NA	NA
6	Calpine Energy Services, L.P.	SF	WSPP-Q	NA	NA	NA
7	Cargill Power Markets, LLC	AD	T-12	NA	NA	NA
8	Citigroup Energy, Inc.	SF	T-12	NA	NA	NA
9	City of Burbank	SF	T-12	NA	NA	NA
10	City of Burbank	SF	WSPP-Q	NA	NA	NA
11	City of Glendale	SF	T-12	NA	NA	NA
12	City of Hurricane	IF	560	NA	NA	NA
13	City of Hurricane	AD	T-12	NA	NA	NA
14	City of Hurricane	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 2018/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.
51			948	948	1
2,528		42,331		42,331	2
-426			-111,805	-111,805	3
21,409		755,425		755,425	4
51,875		906,516		906,516	5
5		113		113	6
100			2,400	2,400	7
1,057,627		31,792,101		31,792,101	8
27,144		849,060		849,060	9
8,096		205,169		205,169	10
800		19,600		19,600	11
145		7,306		7,306	12
-19			-919	-919	13
39		1,715		1,715	14
308,313	5,942,267	9,662,135	-1,078,073	14,526,329	
8,001,159	7,490,743	463,953,015	-231,755,357	239,688,401	
8,309,472	**13,433,010**	**473,615,150**	**-232,833,430**	**254,214,730**	

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 2018/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	City of Redding	SF	T-12	NA	NA	NA
2	City of Roseville	SF	T-12	NA	NA	NA
3	Clatskanie People's Utility District	SF	T-12	NA	NA	NA
4	ConocoPhillips Company	SF	T-12	NA	NA	NA
5	Direct Energy Business Marketing, LLC	SF	T-12	NA	NA	NA
6	DTE Energy Trading, Inc.	SF	T-12	NA	NA	NA
7	EDF Trading North America, LLC	SF	T-12	NA	NA	NA
8	EDF Trading North America, LLC	SF	WSPP-Q	NA	NA	NA
9	El Paso Electric Company	SF	T-12	NA	NA	NA
10	Eugene Water & Electric Board	SF	T-12	NA	NA	NA
11	Exelon Generation Company, LLC	AD	T-12	NA	NA	NA
12	Exelon Generation Company, LLC	SF	T-12	NA	NA	NA
13	Exelon Generation Company, LLC	SF	WSPP-Q	NA	NA	NA
14	Gridforce Energy Management, LLC	SF	T-13	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 2018/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.
44,319		1,157,460		1,157,460	1
71,363		1,710,843		1,710,843	2
7,295		247,676		247,676	3
60,349		2,398,192		2,398,192	4
110,413		3,374,954		3,374,954	5
164,525		5,526,263		5,526,263	6
1,180,286		33,973,960		33,973,960	7
50		2,040		2,040	8
5,777		410,185		410,185	9
17,718		566,040		566,040	10
1,984			57,241	57,241	11
842,579		21,839,373		21,839,373	12
3,618		79,001		79,001	13
696			28,204	28,204	14
308,313	5,942,267	9,662,135	-1,078,073	14,526,329	
8,001,159	7,490,743	463,953,015	-231,755,357	239,688,401	
8,309,472	**13,433,010**	**473,615,150**	**-232,833,430**	**254,214,730**	

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 2018/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	Idaho Power Company	SF	T-13	NA	NA	NA
2	Idaho Power Company	SF	WSPP-Q	NA	NA	NA
3	Imperial Irrigation District	SF	T-12	NA	NA	NA
4	Los Angeles Dept. of Water and Power	SF	T-12	NA	NA	NA
5	Macquarie Energy LLC	SF	T-12	NA	NA	NA
6	Macquarie Energy LLC	SF	WSPP-Q	NA	NA	NA
7	Modesto Irrigation District	SF	T-12	NA	NA	NA
8	Morgan Stanley Capital Group, Inc.	SF	T-12	NA	NA	NA
9	Morgan Stanley Capital Group, Inc.	SF	WSPP-Q	NA	NA	NA
10	Municipal Energy Agency of Nebraska	SF	T-12	NA	NA	NA
11	NaturEner Power Watch, LLC	AD	T-13	NA	NA	NA
12	NaturEner Power Watch, LLC	SF	T-13	NA	NA	NA
13	Nevada Power Company	SF	WSPP-Q	NA	NA	NA
14	NextEra 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.
70			1,827	1,827	1
23,879		749,649		749,649	2
4,538		162,638		162,638	3
52,554		1,774,424		1,774,424	4
610,749		17,518,499		17,518,499	5
150,261		4,045,482		4,045,482	6
118,181		2,945,097		2,945,097	7
515,633		14,871,738		14,871,738	8
126,872		3,268,316		3,268,316	9
16,002		425,845		425,845	10
			84	84	11
63			967	967	12
12,956		454,555		454,555	13
800		28,200		28,200	14
308,313	5,942,267	9,662,135	-1,078,073	14,526,329	
8,001,159	7,490,743	463,953,015	-231,755,357	239,688,401	
8,309,472	**13,433,010**	**473,615,150**	**-232,833,430**	**254,214,730**	

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 2018/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.
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LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
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	NorthWestern Corporation	AD	WSPP-Q	NA	NA	NA
2	NorthWestern Corporation	SF	T-13	NA	NA	NA
3	NorthWestern Corporation	SF	WSPP-Q	NA	NA	NA
4	Portland General Electric Company	SF	T-12	NA	NA	NA
5	Portland General Electric Company	SF	T-13	NA	NA	NA
6	Portland General Electric Company	SF	WSPP-Q	NA	NA	NA
7	Powerex Corporation	AD	T-12	NA	NA	NA
8	Powerex Corporation	SF	T-12	NA	NA	NA
9	Powerex Corporation	SF	WSPP-Q	NA	NA	NA
10	Public Service Company of Colorado	AD	T-12	NA	NA	NA
11	Public Service Company of Colorado	SF	T-12	NA	NA	NA
12	Public Service Company of New Mexico	SF	T-12	NA	NA	NA
13	PUD No. 1 of Chelan County	SF	T-13	NA	NA	NA
14	PUD No. 1 of Douglas County	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 2018/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.
			64	64	1
333			8,817	8,817	2
11,312		424,732		424,732	3
209,176		5,774,320		5,774,320	4
106			4,763	4,763	5
12,828		573,906		573,906	6
56			3,062	3,062	7
160,233		3,314,222		3,314,222	8
270		10,080		10,080	9
1,002			21,352	21,352	10
4,921,799		128,518,984		128,518,984	11
80,606		2,578,697		2,578,697	12
15			658	658	13
1,183		31,439		31,439	14
308,313	5,942,267	9,662,135	-1,078,073	14,526,329	
8,001,159	7,490,743	463,953,015	-231,755,357	239,688,401	
8,309,472	**13,433,010**	**473,615,150**	**-232,833,430**	**254,214,730**	

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 2018/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	PUD No. 1 of Snohomish County	SF	T-12	NA	NA	NA
2	PUD No. 2 of Grant County	SF	T-13	NA	NA	NA
3	Puget Sound Energy, Inc.	SF	T-12	NA	NA	NA
4	Puget Sound Energy, Inc.	SF	T-13	NA	NA	NA
5	Rainbow Energy Marketing Corporation	SF	T-12	NA	NA	NA
6	Rainbow Energy Marketing Corporation	SF	WSPP-Q	NA	NA	NA
7	Sacramento Municipal Utility District	SF	T-12	NA	NA	NA
8	Sacramento Municipal Utility District	SF	T-13	NA	NA	NA
9	Salt River Project	SF	T-12	NA	NA	NA
10	Seattle City Light	SF	T-12	NA	NA	NA
11	Seattle City Light	SF	T-13	NA	NA	NA
12	Sempra Gas & Power Marketing, Llc	AD	T-12	NA	NA	NA
13	Sempra Gas & Power Marketing, Llc	SF	T-12	NA	NA	NA
14	Shell Energy North America (US), L.P.	AD	T-12	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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.
2,540		81,818		81,818	1
60			901	901	2
70,859		1,939,448		1,939,448	3
114			4,250	4,250	4
1,071		24,270		24,270	5
3,200		77,600		77,600	6
22,515		355,231		355,231	7
37			1,846	1,846	8
6,284		362,644		362,644	9
19,355		683,615		683,615	10
9			291	291	11
124			4,352	4,352	12
1,119,343		31,221,924		31,221,924	13
			21,351	21,351	14
308,313	5,942,267	9,662,135	-1,078,073	14,526,329	
8,001,159	7,490,743	463,953,015	-231,755,357	239,688,401	
8,309,472	**13,433,010**	**473,615,150**	**-232,833,430**	**254,214,730**	

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 2018/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	Shell Energy North America (US), L.P.	SF	T-12	NA	NA	NA
2	Shell Energy North America (US), L.P.	SF	WSPP-Q	NA	NA	NA
3	Sierra Pacific Power Company	SF	T-13	NA	NA	NA
4	Southern California Edison Company	SF	T-12	NA	NA	NA
5	Tacoma Power	SF	T-12	NA	NA	NA
6	Tenaska Power Services Co.	SF	T-12	NA	NA	NA
7	Tenaska Power Services Co.	SF	WSPP-Q	NA	NA	NA
8	The Energy Authority, Inc.	SF	T-12	NA	NA	NA
9	TransAlta Energy Marketing (U.S.) Inc.	AD	T-12	NA	NA	NA
10	TransAlta Energy Marketing (U.S.) Inc.	SF	T-12	NA	NA	NA
11	TransAlta Energy Marketing (U.S.) Inc.	OS	T-12	NA	NA	NA
12	TransCanada Energy Sales Ltd.	SF	T-12	NA	NA	NA
13	Tri-State Gen. and Trans. Assoc.	AD	T-12	NA	NA	NA
14	Tri-State Gen. and Trans. Assoc.	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.
440,723		12,162,451		12,162,451	1
161,920		4,045,038		4,045,038	2
175			5,260	5,260	3
451,844		12,415,059		12,415,059	4
17,957		497,472		497,472	5
30,460		945,850		945,850	6
132,012		3,610,835		3,610,835	7
115,256		4,042,946		4,042,946	8
			-9,037	-9,037	9
175,449		5,292,536		5,292,536	10
			500	500	11
4,400		145,600		145,600	12
			-60	-60	13
34,683		714,146		714,146	14
308,313	5,942,267	9,662,135	-1,078,073	14,526,329	
8,001,159	7,490,743	463,953,015	-231,755,357	239,688,401	
8,309,472	**13,433,010**	**473,615,150**	**-232,833,430**	**254,214,730**	

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	Tucson Electric Power Company	SF	T-12	NA	NA	NA
2	Tucson Electric Power Company	SF	WSPP-Q	NA	NA	NA
3	Turlock Irrigation District	SF	T-12	NA	NA	NA
4	Turlock Irrigation District	SF	T-13	NA	NA	NA
5	UNS Electric, Inc.	SF	T-12	NA	NA	NA
6	Utah Associated Municipal Power Systems	SF	T-12	NA	NA	NA
7	Utah Associated Municipal Power Systems	SF	WSPP-Q	NA	NA	NA
8	Utah Municipal Power Agency	SF	T-12	NA	NA	NA
9	Utah Municipal Power Agency	SF	WSPP-Q	NA	NA	NA
10	Vitol Inc.	SF	T-12	NA	NA	NA
11	Westar Energy, Inc.	SF	T-12	NA	NA	NA
12	Western Area Power Administration	SF	T-12	NA	NA	NA
13	Transmission Loss Sales Revenue	AD	T-11	NA	NA	NA
14	Transmission Loss Sales Revenue	OS	T-11	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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.
183,097		5,916,407		5,916,407	1
50		1,850		1,850	2
84,113		2,051,108		2,051,108	3
5			146	146	4
87,251		2,410,485		2,410,485	5
400		11,868		11,868	6
56,374		1,568,041		1,568,041	7
12		558		558	8
8,805		152,806	4,218	157,024	9
2,400		44,100		44,100	10
679		24,036		24,036	11
203,719		6,595,452		6,595,452	12
1,545			41,516	41,516	13
228,183			6,660,567	6,660,567	14
308,313	5,942,267	9,662,135	-1,078,073	14,526,329	
8,001,159	7,490,743	463,953,015	-231,755,357	239,688,401	
8,309,472	**13,433,010**	**473,615,150**	**-232,833,430**	**254,214,730**	

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 2018/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.
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SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Netting - Bookouts		NA	NA	NA	NA
2	Netting - Trading		NA	NA	NA	NA
3	Accrual		NA	NA	NA	NA
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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 2018/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.
-8,968,222			-236,899,122	-236,899,122	1
			-2,786,566	-2,786,566	2
34,224			960,822	960,822	3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
308,313	5,942,267	9,662,135	-1,078,073	14,526,329	
8,001,159	7,490,743	463,953,015	-231,755,357	239,688,401	
8,309,472	**13,433,010**	**473,615,150**	**-232,833,430**	**254,214,730**	

Schedule Page: 310 Line No.: 4 Column: j

```
$  (780,985) Load retention payment
      8,989  Settlement adjustment
   (342,785) Customer service charges related to:
               - Schedule 94, Energy balancing account
               - Schedule 98, Renewable energy adjustment
               - Schedule 196, Utah Sustainable Transportation and Energy Plan
$(1,114,781)
```

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

Complete name is Navajo Tribal Utility Authority (Mexican Hat).

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

Complete name is Navajo Tribal Utility Authority (Red Mesa).

Schedule Page: 310 Line No.: 7 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.: 14 Column: j

Reserve share.

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

Reserve share.

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

Settlement adjustment.

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

Settlement Adjustment.

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

Black Hills Power, Inc. - contract termination date: December 31, 2023.

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

Settlement adjustment.

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

Service Agreement 37

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

Settlement Adjustment.

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

Service Agreement 37

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

Reserve share.

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

Settlement adjustment.

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

Settlement adjustment.

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

Complete name is British Columbia Hydro and Power Authority.

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

Reserve share.

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

Settlement adjustment.

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

Settlement adjustment.

Schedule Page: 310.2 Line No.: 7 Column: b

Settlement adjustment.

Schedule Page: 310.2 Line No.: 7 Column: j
Settlement adjustment.

Schedule Page: 310.2 Line No.: 13 Column: b
Settlement adjustment.

Schedule Page: 310.2 Line No.: 13 Column: j
Settlement adjustment.

Schedule Page: 310.3 Line No.: 11 Column: b
Settlement adjustment.

Schedule Page: 310.3 Line No.: 11 Column: j
Settlement adjustment.

Schedule Page: 310.3 Line No.: 14 Column: j
Reserve share.

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

Schedule Page: 310.4 Line No.: 4 Column: a
Complete name is Los Angeles Department of Water and Power.

Schedule Page: 310.4 Line No.: 11 Column: b
Settlement adjustment.

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

Schedule Page: 310.4 Line No.: 12 Column: j
Reserve share.

Schedule Page: 310.4 Line No.: 13 Column: a
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: 310.5 Line No.: 1 Column: b
Settlement adjustment.

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

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

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

Schedule Page: 310.5 Line No.: 7 Column: b
Settlement adjustment.

Schedule Page: 310.5 Line No.: 7 Column: j
Settlement adjustment.

Schedule Page: 310.5 Line No.: 10 Column: b
Settlement adjustment.

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

Schedule Page: 310.5 Line No.: 13 Column: a
Complete name is Public Utility District No. 1 of Chelan County.

Schedule Page: 310.5 Line No.: 13 Column: j
Reserve share.

Schedule Page: 310.5 Line No.: 14 Column: a
Complete name is Public Utility District No. 1 of Douglas County.

Schedule Page: 310.6 Line No.: 1 Column: a
Complete name is Public Utility District No. 1 of Snohomish County.

Schedule Page: 310.6 Line No.: 2 Column: a
Complete name is Public Utility District No. 2 of Grant County.

Schedule Page: 310.6 Line No.: 2 Column: j
Reserve share.

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

Schedule Page: 310.6 Line No.: 8 Column: j
Reserve share.

Schedule Page: 310.6 Line No.: 11 Column: j
Reserve share.

Schedule Page: 310.6 Line No.: 12 Column: b
Settlement adjustment.

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

Schedule Page: 310.6 Line No.: 14 Column: b
Settlement adjustment.

Schedule Page: 310.6 Line No.: 14 Column: j
Settlement adjustment.

Schedule Page: 310.7 Line No.: 3 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: 310.7 Line No.: 3 Column: j
Reserve share.

Schedule Page: 310.7 Line No.: 9 Column: b
Settlement adjustment.

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

Schedule Page: 310.7 Line No.: 11 Column: b
Pond sales.

Schedule Page: 310.7 Line No.: 11 Column: j
Pond sales.

Schedule Page: 310.7 Line No.: 13 Column: a
This footnote applies to all occurrences of "Tri-State Gen. and Trans. Assoc." on pages 310-311. Complete name is Tri-State Generation and Transmission Association, Inc.

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

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

Schedule Page: 310.8 Line No.: 4 Column: j
Reserve share.

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

Schedule Page: 310.8 Line No.: 13 Column: b
Settlement adjustment.

Schedule Page: 310.8 Line No.: 13 Column: j
Settlement adjustment.

Schedule Page: 310.8 Line No.: 14 Column: b
Transmission loss sales revenues collected from PacifiCorp's third party transmission service customers.

Schedule Page: 310.8 Line No.: 14 Column: j
Transmission loss sales revenues collected from PacifiCorp's third party transmission service customers.

Schedule Page: 310.9 Line No.: 1 Column: j
Reflects transactions that did not physically settle.

Schedule Page: 310.9 Line No.: 2 Column: j
Reflects transactions that did not physically settle.

Schedule Page: 310.9 Line No.: 3 Column: j

Represents the difference between actual non-requirement sales revenues for the period as reflected on the individual line items within this schedule and the accruals charged to Account 447, Sales for resale, during the period.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	17,846,918	18,564,129
5	(501) Fuel	815,215,918	836,254,849
6	(502) Steam Expenses	80,653,310	75,578,998
7	(503) Steam from Other Sources	4,714,446	4,677,095
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,538,384	1,215,091
10	(506) Miscellaneous Steam Power Expenses	24,373,827	12,187,163
11	(507) Rents	488,625	549,315
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	944,831,428	949,026,640
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	7,987,432	7,999,631
16	(511) Maintenance of Structures	26,949,381	30,784,444
17	(512) Maintenance of Boiler Plant	94,244,196	87,947,278
18	(513) Maintenance of Electric Plant	40,477,428	30,041,778
19	(514) Maintenance of Miscellaneous Steam Plant	9,735,906	12,751,402
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	179,394,343	169,524,533
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	1,124,225,771	1,118,551,173
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	8,478,869	8,658,615
45	(536) Water for Power	38,379	120,631
46	(537) Hydraulic Expenses	4,538,642	3,938,899
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses	17,012,228	15,714,600
49	(540) Rents	1,222,268	1,898,750
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	31,290,386	30,331,495
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	470	389
54	(542) Maintenance of Structures	717,063	732,787
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,426,368	2,042,717
56	(544) Maintenance of Electric Plant	1,683,128	2,518,525
57	(545) Maintenance of Miscellaneous Hydraulic Plant	3,880,263	3,269,988
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	7,707,292	8,564,406
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	38,997,678	38,895,901

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	285,602	343,362
63	(547) Fuel	239,131,815	214,054,042
64	(548) Generation Expenses	17,616,683	16,194,351
65	(549) Miscellaneous Other Power Generation Expenses	5,107,905	5,434,018
66	(550) Rents	4,360,755	3,717,449
67	TOTAL Operation (Enter Total of lines 62 thru 66)	266,502,760	239,743,222
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	4,396,956	2,717,666
71	(553) Maintenance of Generating and Electric Plant	17,759,259	15,757,596
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	3,138,006	3,063,915
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	25,294,221	21,539,177
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	291,796,981	261,282,399
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	667,434,104	639,445,881
77	(556) System Control and Load Dispatching	1,211,514	1,310,515
78	(557) Other Expenses	41,691,162	43,501,285
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	710,336,780	684,257,681
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	2,165,357,210	2,102,987,154
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	6,772,651	6,347,854
84			
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	7,234,514	6,954,702
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	1,384,344	2,007,912
89	(561.5) Reliability, Planning and Standards Development	1,968,543	1,674,277
90	(561.6) Transmission Service Studies	102,948	72,957
91	(561.7) Generation Interconnection Studies	1,755,384	1,696,771
92	(561.8) Reliability, Planning and Standards Development Services	7,447,677	7,484,166
93	(562) Station Expenses	2,901,944	3,413,321
94	(563) Overhead Lines Expenses	864,557	505,147
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	135,021,597	134,473,119
97	(566) Miscellaneous Transmission Expenses	2,859,169	2,349,109
98	(567) Rents	2,138,345	2,161,509
99	TOTAL Operation (Enter Total of lines 83 thru 98)	170,451,673	169,140,844
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	1,444,581	1,062,627
102	(569) Maintenance of Structures	41,891	51,218
103	(569.1) Maintenance of Computer Hardware	67,060	155,815
104	(569.2) Maintenance of Computer Software	825,322	701,841
105	(569.3) Maintenance of Communication Equipment	5,238,837	4,911,057
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	11,984,857	11,826,106
108	(571) Maintenance of Overhead Lines	16,147,738	16,851,778
109	(572) Maintenance of Underground Lines	81,815	19,786
110	(573) Maintenance of Miscellaneous Transmission Plant	222,170	84,769
111	TOTAL Maintenance (Total of lines 101 thru 110)	36,054,271	35,664,997
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	206,505,944	204,805,841

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	8,848,063	8,961,333
135	(581) Load Dispatching	11,541,737	10,667,212
136	(582) Station Expenses	4,076,355	3,986,742
137	(583) Overhead Line Expenses	9,211,450	7,809,454
138	(584) Underground Line Expenses	2,063	787
139	(585) Street Lighting and Signal System Expenses	247,796	152,074
140	(586) Meter Expenses	2,790,673	4,220,933
141	(587) Customer Installations Expenses	14,205,310	13,556,316
142	(588) Miscellaneous Expenses	1,196,149	1,975,285
143	(589) Rents	3,182,216	3,178,795
144	TOTAL Operation (Enter Total of lines 134 thru 143)	55,301,812	54,508,931
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	5,835,359	5,400,066
147	(591) Maintenance of Structures	2,142,078	2,463,160
148	(592) Maintenance of Station Equipment	9,062,978	9,002,066
149	(593) Maintenance of Overhead Lines	89,351,304	86,667,266
150	(594) Maintenance of Underground Lines	24,670,628	25,465,187
151	(595) Maintenance of Line Transformers	974,547	969,563
152	(596) Maintenance of Street Lighting and Signal Systems	2,965,826	2,930,590
153	(597) Maintenance of Meters	225,334	138,623
154	(598) Maintenance of Miscellaneous Distribution Plant	6,728,870	10,103,297
155	TOTAL Maintenance (Total of lines 146 thru 154)	141,956,924	143,139,818
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	197,258,736	197,648,749
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	2,477,399	2,362,629
160	(902) Meter Reading Expenses	19,056,668	19,666,217
161	(903) Customer Records and Collection Expenses	50,336,486	47,770,750
162	(904) Uncollectible Accounts	11,655,692	15,424,209
163	(905) Miscellaneous Customer Accounts Expenses	135,391	881,737
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	83,661,636	86,105,542

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 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	117,633	288,761
168	(908) Customer Assistance Expenses	90,120,906	87,894,734
169	(909) Informational and Instructional Expenses	5,820,368	3,335,567
170	(910) Miscellaneous Customer Service and Informational Expenses	41,342	3,182
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	96,100,249	91,522,244
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	72,265,963	70,991,765
182	(921) Office Supplies and Expenses	9,971,031	9,355,736
183	(Less) (922) Administrative Expenses Transferred-Credit	31,909,798	31,140,474
184	(923) Outside Services Employed	19,890,624	23,869,244
185	(924) Property Insurance	12,338,561	14,821,125
186	(925) Injuries and Damages	16,740,134	9,434,369
187	(926) Employee Pensions and Benefits	113,736,594	98,462,764
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	22,484,361	22,853,804
190	(929) (Less) Duplicate Charges-Cr.	128,629,971	103,489,435
191	(930.1) General Advertising Expenses	580	1,435
192	(930.2) Miscellaneous General Expenses	2,225,689	2,272,508
193	(931) Rents	2,723,369	3,040,328
194	TOTAL Operation (Enter Total of lines 181 thru 193)	111,837,137	120,473,169
195	Maintenance		
196	(935) Maintenance of General Plant	23,525,832	21,636,566
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	135,362,969	142,109,735
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	2,884,246,744	2,825,179,265

Schedule Page: 320 Line No.: 185 Column: b

Adjustment to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, is as follows:

Account (a)	Ref. Line No. (Column)	Amount for Current Year (b)
(924) Property Insurance	185(b)	$ 12,338,561
Less: Situs property loss reserves, net of reimbursements(1)		7,135,301
Revised (924) Property Insurance		$ 5,203,260

(1) To adjust PacifiCorp's formula rate, per FERC Docket No. FA16-4-000 for situs property loss reserves, net of reimbursements.

Schedule Page: 320 Line No.: 187 Column: b

As required by Commission regulations, the cost of pensions, postretirement other than pensions and other employee benefits are reported in Account 926, Employee pensions and benefits. Pensions and benefits expense is associated with labor and generally charged to operations and maintenance expense and construction work in progress, therefore, pursuant to FERC Docket No. FA16-4-000, these pensions and benefits are offset in Account 929, Duplicate charges-credit.

In accordance with PacifiCorp's formula rate settlement agreement in FERC Docket No. ER11-3643-000, Section 3.4.2.9 states, in part, all regulatory asset amortizations should be excluded from the calculation of the wholesale transmission revenue requirement and charges under the wholesale formula rates, unless approved by the Commission. During the year ended December 31, 2018, pension and postretirement regulatory asset amortization was $(2,152,679).

Schedule Page: 320 Line No.: 190 Column: b

Includes the offset of pensions and benefits in Account 926, Employee pensions and benefits, pursuant to FERC Docket No. FA16-4-000.

Schedule Page: 320 Line No.: 197 Column: b

Adjustments to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, are as follows:

Account (a)	Ref. Line No. (Column)	Amount for Current Year (b)
TOTAL Administrative & General Expenses	197(b)	$ 135,362,969
Less: Situs property loss reserves, net of reimbursements(1)		7,135,301
Less: Pension and postretirement regulatory asset amort. (2)		(2,152,679)
Revised TOTAL Administrative & General Expenses		$ 130,380,347

(1) To adjust Account 924, Property insurance. Refer to footnote on page 320, line no. 185, column (b)
(2) To adjust Account 926, Employee pensions and benefits. Refer to footnote on page 320, line no. 187, 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 2018/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	Adams Solar Center LLC	LU		NA	NA	NA
3	Apple, Inc.	LU		NA	NA	NA
4	Arizona Electric Power Cooperative	SF		NA	NA	NA
5	Arizona Public Service Company	LF		NA	NA	NA
6	Arizona Public Service Company	SF		NA	NA	NA
7	Arizona Public Service Company	AD		NA	NA	NA
8	Avangrid Renewables, LLC	SF		NA	NA	NA
9	Avangrid Renewables, LLC	AD		NA	NA	NA
10	Avista Corporation	SF		NA	NA	NA
11	Ballard Hog Farms Inc.	LU		0	0	0
12	Basin Electric Power Cooperative	SF		NA	NA	NA
13	BC Solar, LLC	LU		NA	NA	NA
14	BC Solar, LLC	AD		NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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)	
							1
12,017				691,660	1,987	693,647	2
7,654				612,189		612,189	3
7,700				356,200		356,200	4
47,352				1,214,036		1,214,036	5
60,898				2,564,885		2,564,885	6
					-3	-3	7
1,907,012				65,591,362	161	65,591,523	8
44					1,269	1,269	9
200,986				7,462,539	7,596	7,470,135	10
288			5,988	14,683		20,671	11
193,996				10,455,542		10,455,542	12
18,530				1,162,175		1,162,175	13
196					4,142	4,142	14
13,668,425	7,967,992	7,994,889	32,377,530	904,189,538	-269,132,964	667,434,104	

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 2018/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	Bear Creek Solar Center, LLC	LU		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	1
5	Big Top, LLC	LU		NA	NA	NA
6	Biomass One, L.P.	LU		NA	NA	NA
7	Birch Power Company, Inc.	LU		NA	NA	NA
8	Black Cap Solar, LLC	LU		NA	NA	NA
9	Black Hills Power, Inc.	SF		NA	NA	NA
10	Bly Solar Center, LLC	LU		NA	NA	NA
11	Bonneville Power Administration	LF		NA	NA	NA
12	Bonneville Power Administration	SF		NA	NA	NA
13	Bonneville Power Administration	AD		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)	
5,459				268,343		268,343	1
31				3,064		3,064	2
947				83,513		83,513	3
6,270			422,750	319,793		742,543	4
4,127				317,576		317,576	5
166,002				12,577,426	2,397,750	14,975,176	6
12,804				816,901		816,901	7
527				24,483		24,483	8
11,370				843,789		843,789	9
567				28,588		28,588	10
				72	129,160	129,232	11
770,374				21,378,590	44,417	21,423,007	12
					2	2	13
326				12,068		12,068	14
13,668,425	7,967,992	7,994,889	32,377,530	904,189,538	-269,132,964	667,434,104	

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	Box Canyon Limited Partnership	LU		2	2	1
2	BP Energy Company	SF		NA	NA	NA
3	Brigham Young University - Idaho	IU		NA	NA	NA
4	Brookfield Energy Marketing LP	SF		NA	NA	NA
5	Buckhorn Solar, LLC	LU		3	3	1
6	Butter Creek Power, LLC	LU		NA	NA	NA
7	C Drop Hydro, LLC	LU		NA	NA	NA
8	California Independent System Operator	SF		NA	NA	NA
9	California Independent System Operator	AD		NA	NA	NA
10	Calpine Energy Services, L.P.	SF		NA	NA	NA
11	Cargill Power Markets, LLC	AD		NA	NA	NA
12	Cedar Valley Solar, LLC	LU		3	3	1
13	Central Oregon Irrigation District	LU		4	4	3
14	Chevron U.S.A. Inc.	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 2018/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)	
8,755			197,023	1,267,690		1,464,713	1
2,313,425				70,194,022		70,194,022	2
38,685				2,134,001		2,134,001	3
17,912				1,854,441		1,854,441	4
5,972			423,962	304,592		728,554	5
13,533				1,037,251		1,037,251	6
1,777				142,017		142,017	7
14,420				2,005,258		2,005,258	8
					-61,987	-61,987	9
90,289				3,812,654		3,812,654	10
100					2,400	2,400	11
5,946			420,160	303,266		723,426	12
35,514			450,587	3,813,278		4,263,865	13
22,804				296,057		296,057	14
13,668,425	7,967,992	7,994,889	32,377,530	904,189,538	-269,132,964	667,434,104	

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	Chiloquin Solar LLC	LU		NA	NA	NA
2	Chopin Wind, LLC	LU		NA	NA	NA
3	Citigroup Energy, Inc.	SF		NA	NA	NA
4	City of Albany	LU		NA	NA	NA
5	City of Anaheim	SF		NA	NA	NA
6	City of Astoria	LU		NA	NA	NA
7	City of Burbank	SF		NA	NA	NA
8	City of Glendale	SF		NA	NA	NA
9	City of Hurricane	LF		NA	NA	NA
10	City of Hurricane	AD		NA	NA	NA
11	City of Idaho Falls	LU		NA	NA	NA
12	City of Idaho Falls	AD		NA	NA	NA
13	City of Portland, Water Bureau	LU		NA	NA	NA
14	City of Preston Idaho	AD		NA	NA	NA
	Total					

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
20,037				831,886		831,886	1
31,244				1,702,414		1,702,414	2
923,395				24,342,345		24,342,345	3
1,133				88,359		88,359	4
210				1,206		1,206	5
19				730		730	6
2,585				157,888		157,888	7
1,400				79,600		79,600	8
2,699				183,137		183,137	9
3					216	216	10
62,828					1,640,364	1,640,364	11
					11,509	11,509	12
161				12,868		12,868	13
					-325	-325	14
13,668,425	7,967,992	7,994,889	32,377,530	904,189,538	-269,132,964	667,434,104	

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 2018/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	City of Preston Idaho	LU		NA	NA	NA
2	City of Redding	SF		NA	NA	NA
3	City of Roseville	SF		NA	NA	NA
4	Clatskanie People's Utility District	SF		NA	NA	NA
5	Commercial Energy Management Inc.	LU		NA	NA	NA
6	Confederate Tribes of Warm Springs	LU		NA	NA	NA
7	ConocoPhillips Company	SF		NA	NA	NA
8	Consolidated Irrigation Company	LU		NA	NA	NA
9	Cottonwood Hydro, LLC	IU		NA	NA	NA
10	Cottonwood Hydro, LLC	AD		NA	NA	NA
11	Crook County Solar 1, LLC	LU		NA	NA	NA
12	Deschutes Valley Water District	LU		4	3	3
13	Deseret Generation and Transmission	LF		100	100	81
14	Direct Energy Business Marketing, 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 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.
2,505				145,643		145,643	1
1,648				60,770		60,770	2
29,526				2,969,160		2,969,160	3
1,703				13,987		13,987	4
2,400				136,725		136,725	5
303				11,339		11,339	6
204,293				6,658,999		6,658,999	7
2,145				125,911		125,911	8
3,102				149,020		149,020	9
12					553	553	10
1,253				48,247		48,247	11
24,468			380,796	3,320,355		3,701,151	12
489,799			17,689,080	11,046,121	4,565,640	33,300,841	13
4,674				766,743		766,743	14
13,668,425	7,967,992	7,994,889	32,377,530	904,189,538	-269,132,964	667,434,104	

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 2018/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	Dorena Hydro, LLC	LU		NA	NA	NA
2	Douglas County	LU		0	0	0
3	Douglas County, Inc.	LU		NA	NA	NA
4	Draper Irrigation Company	IU		NA	NA	NA
5	Dry Creek LLC	LU		NA	NA	NA
6	Dry Creek LLC	AD		NA	NA	NA
7	DTE Energy Trading, Inc.	SF		NA	NA	NA
8	eBay Inc.	LU		NA	NA	NA
9	EDF Trading North America, LLC	SF		NA	NA	NA
10	El Paso Electric Company	SF		NA	NA	NA
11	Elbe Solar Center, LLC	LU		NA	NA	NA
12	Elbe Solar Center, LLC	LU		NA	NA	NA
13	Element Markets, LLC	OS		NA	NA	NA
14	Enterprise Solar, 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)	
9,322				746,803		746,803	1
2,417			51,572	368,598		420,170	2
3,740				120,039		120,039	3
23				1,618		1,618	4
12,579				773,030		773,030	5
					4,662	4,662	6
675				14,175		14,175	7
244				19,309		19,309	8
583,508				14,962,356		14,962,356	9
35,086				1,278,092		1,278,092	10
					557	557	11
10,629				697,025		697,025	12
					35,478	35,478	13
					435,132	435,132	14
13,668,425	7,967,992	7,994,889	32,377,530	904,189,538	-269,132,964	667,434,104	

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 2018/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	Enterprise Solar, LLC	LU		NA	NA	NA
2	Escalante Solar I, LLC	LU		NA	NA	NA
3	Escalante Solar II, LLC	LU		NA	NA	NA
4	Escalante Solar III, LLC	LU		NA	NA	NA
5	Eugene Water & Electric Board	SF		NA	NA	NA
6	Eurus Combine Hills I, LLC	LU		NA	NA	NA
7	Exelon Generation Company, LLC	SF		NA	NA	NA
8	Exelon Generation Company, LLC	AD		NA	NA	NA
9	ExxonMobil Production Company	LU		NA	NA	NA
10	Fall River Rural Electric Cooperative	LU		NA	NA	NA
11	Falls Creek H.P. Limited Partnership	LU		3	3	0
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					

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.
225,336				12,266,333		12,266,333	1
204,549				10,936,596		10,936,596	2
208,002				10,565,876		10,565,876	3
206,357				10,118,592		10,118,592	4
8,136				162,149		162,149	5
113,681				5,527,154		5,527,154	6
973,635				23,998,722		23,998,722	7
800					19,400	19,400	8
376				7,252		7,252	9
28,298				1,917,357		1,917,357	10
12,544			161,908	1,741,138		1,903,046	11
4,036				322,986		322,986	12
23,426				1,753,985		1,753,985	13
182				19,944		19,944	14
13,668,425	7,967,992	7,994,889	32,377,530	904,189,538	-269,132,964	667,434,104	

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 2018/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	Finley BioEnergy, LLC	LU		NA	NA	NA
2	Flathead Electric Cooperative, Inc.	LF		NA	NA	NA
3	Flathead Electric Cooperative, Inc.	AD		NA	NA	NA
4	Foote Creek II, LLC	LU		NA	NA	NA
5	Foote Creek III, 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	Georgetown Irrigation Company	LU		NA	NA	NA
9	Grand Valley Power	LF		NA	NA	NA
10	Granite Mountain Solar East, LLC	LU		NA	3	NA
11	Granite Mountain Solar West, LLC	LU		NA	NA	NA
12	Granite Peak Solar, LLC	LU		3	3	1
13	Greenville Solar, LLC	LU		2	2	1
14	Gridforce Energy Management, 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)	
31,494				2,452,791		2,452,791	1
371				9,708		9,708	2
					258	258	3
5,936				120,214		120,214	4
73,668				1,625,978		1,625,978	5
28,785				2,206,029		2,206,029	6
27,321				2,097,656		2,097,656	7
2,245				143,501	-2,511	140,990	8
35				8,228		8,228	9
208,091				10,761,454		10,761,454	10
123,567				6,733,089		6,733,089	11
6,083			240,355	211,826		452,181	12
4,091			316,317	208,616		524,933	13
126					4,706	4,706	14
13,668,425	7,967,992	7,994,889	32,377,530	904,189,538	-269,132,964	667,434,104	

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 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Hammerich 1 & 2	LU		NA	NA	NA
2	Harold Foster & Robert Walker	LU		NA	NA	NA
3	Hayward Paul Luckey and Joanne Luckey	LU		NA	NA	NA
4	Idaho Power Company	OS		NA	NA	NA
5	Idaho Power Company	SF		NA	NA	NA
6	Iron Springs Solar, LLC	LU		NA	NA	NA
7	J Bar 9 Ranch, Inc.	LU		NA	NA	NA
8	Jake Amy	LU		NA	NA	NA
9	Jake Amy	AD		NA	NA	NA
10	Joseph Community Solar, LLC	LU		NA	NA	NA
11	Keeton 1 & 2	LU		NA	NA	NA
12	Kettle Butte Digester LLC	LU		NA	NA	NA
13	Klamath Falls Solar 1, LLC	LU		NA	NA	NA
14	Klamath Falls Solar 2, LLC	IU		NA	NA	NA
	Total					

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
397				14,903		14,903	1
96				3,071		3,071	2
237				13,203		13,203	3
2,599				16,399		16,399	4
312,305				8,157,782	1,754	8,159,536	5
211,796				11,329,607		11,329,607	6
56				1,261		1,261	7
2,180				134,660		134,660	8
22					1,397	1,397	9
731				25,377		25,377	10
384				14,550		14,550	11
7,008				488,247		488,247	12
1,105				69,179		69,179	13
5,444				226,254		226,254	14
13,668,425	7,967,992	7,994,889	32,377,530	904,189,538	-269,132,964	667,434,104	

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	Klamath Falls Solar 2, LLC	AD		NA	NA	NA
2	Lacomb Irrigation District	LU		NA	NA	NA
3	Laho Solar, LLC	LU		3	3	1
4	Latigo Wind Park, LLC	LU		NA	NA	NA
5	Los Angeles Dept. of Water and Power	SF		NA	NA	NA
6	Loyd Fery	LU		NA	NA	NA
7	Macquarie Energy LLC	SF		NA	NA	NA
8	Marsh Valley Hydro Electric Company	LU		NA	NA	NA
9	Meadow Creek Project Company LLC	LU		NA	NA	NA
10	Middle Fork Irrigation District	LU		NA	NA	NA
11	Middle Fork Irrigation District	AD		NA	NA	NA
12	Milford Flat Solar, LLC	LU		0	3	1
13	Milford Flat Solar, LLC	AD		NA	NA	NA
14	Mink Creek Hydro 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)	
					7	7	1
4,223				100,764	63,583	164,347	2
6,413			241,235	223,304		464,539	3
155,670				9,376,950		9,376,950	4
23,230				2,061,517		2,061,517	5
283				6,311		6,311	6
294,957				11,795,249		11,795,249	7
6,868				438,777		438,777	8
346,181				25,979,539		25,979,539	9
23,133				1,621,161		1,621,161	10
					-250	-250	11
6,288			240,992	218,937		459,929	12
-241			446,151		114,177	560,328	13
9,286				575,737		575,737	14
13,668,425	7,967,992	7,994,889	32,377,530	904,189,538	-269,132,964	667,434,104	

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 2018/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	Monsanto Company	IU		NA	NA	NA
2	Morgan City Corporation	LF		NA	NA	NA
3	Morgan Stanley Capital Group, Inc.	SF		NA	NA	NA
4	Morgan Stanley Capital Group, Inc.	AD		NA	NA	NA
5	Mountain Wind Power, LLC	LU		NA	NA	NA
6	Mountain Wind Power II, LLC	LU		NA	NA	NA
7	Municipal Energy Agency of Nebraska	SF		NA	NA	NA
8	Myron Jones	LU		NA	NA	NA
9	NaturEner Power Watch, LLC	SF		NA	NA	NA
10	Nevada Power Company	SF		NA	NA	NA
11	Nevada Power Company	AD		NA	NA	NA
12	NextEra Energy Marketing, LLC	SF		NA	NA	NA
13	NextEra Energy Power Marketing, LLC	SF		NA	NA	NA
14	Nichols Gap Limited Partnership	LU		1	1	0
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					20,003,760	20,003,760	1
8				735		735	2
930,047				35,300,441		35,300,441	3
675					40,500	40,500	4
158,793				8,823,135		8,823,135	5
219,045				14,112,156		14,112,156	6
4,221				334,965		334,965	7
776				45,929		45,929	8
3					87	87	9
25,402				836,948		836,948	10
					1,722	1,722	11
2,675				96,750		96,750	12
2,000				58,600		58,600	13
3,331			41,588	479,286		520,874	14
13,668,425	7,967,992	7,994,889	32,377,530	904,189,538	-269,132,964	667,434,104	

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 2018/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	Nichols Gap Limited Partnership	AD		NA	NA	NA
2	Nicholson's Sunny Bar Ranch	LU		NA	NA	NA
3	Nicholson's Sunny Bar Ranch	AD		NA	NA	NA
4	NorthWestern Corporation	SF		NA	NA	NA
5	NorWest Energy 2, LLC	IU		NA	NA	NA
6	NorWest Energy 7, LLC	IU		NA	NA	NA
7	NorWest Energy 7, LLC	AD		NA	NA	NA
8	NorWest Energy 9, LLC	IU		NA	NA	NA
9	Nucor Corporation	IU		NA	NA	NA
10	Obsidian Renewables, LLC	LU		NA	NA	NA
11	Old Mill Solar, LLC	LU		NA	NA	NA
12	OR Solar 3, LLC	LU		NA	NA	NA
13	OR Solar 3, LLC	AD		NA	NA	NA
14	OR Solar 5, 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)	
			-822			-822	1
1,802				114,189		114,189	2
-7					-434	-434	3
8,021				102,390	7,382	109,772	4
21,651				1,356,832		1,356,832	5
18,684				1,171,283		1,171,283	6
					-88	-88	7
1,721				65,767		65,767	8
					7,201,200	7,201,200	9
764				33,505		33,505	10
10,441				783,097		783,097	11
22,140				918,696		918,696	12
					-71	-71	13
18,491				767,252		767,252	14
13,668,425	7,967,992	7,994,889	32,377,530	904,189,538	-269,132,964	667,434,104	

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	OR Solar 6, LLC	LU		NA	NA	NA
2	OR Solar 6, LLC	AD		NA	NA	NA
3	OR Solar 8, LLC	LU		NA	NA	NA
4	Oregon Environmental Industries, LLC	LU		NA	NA	NA
5	Oregon Institute of Technology	LU		NA	NA	NA
6	Oregon Solar Incentive	LU		NA	NA	NA
7	Oregon State University	LU		NA	NA	NA
8	Oregon Trail Windfarm, LLC	LU		NA	NA	NA
9	OSLH, LLC	IU		NA	NA	NA
10	Pacific Canyon Windfarm, LLC	LU		NA	NA	NA
11	Pavant Solar LLC	LU		NA	NA	NA
12	Pavant Solar II LLC	LU		NA	NA	NA
13	Pavant Solar III LLC	LU		NA	NA	NA
14	Pioneer Wind Park I, 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)	
23,954				993,231		993,231	1
					-295	-295	2
22,133				918,236		918,236	3
16,864				1,213,418		1,213,418	4
247				12,023		12,023	5
11,159				421,596		421,596	6
149				1,799		1,799	7
26,503				2,029,522		2,029,522	8
20,796				863,894		863,894	9
20,724				1,594,479		1,594,479	10
121,658				4,637,217	182,486	4,819,703	11
121,567				3,540,488		3,540,488	12
50,512				2,667,026		2,667,026	13
253,252				10,195,730		10,195,730	14
13,668,425	7,967,992	7,994,889	32,377,530	904,189,538	-269,132,964	667,434,104	

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 2018/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	Platte River Power Authority	SF		NA	NA	NA
2	Portland General Electric Company	LF		NA	NA	NA
3	Portland General Electric Company	AD		NA	NA	NA
4	Portland General Electric Company	SF		NA	NA	NA
5	Power County Wind Park North, LLC	LU		NA	NA	NA
6	Power County Wind Park South, LLC	LU		NA	NA	NA
7	Powerex Corporation	OS		NA	NA	NA
8	Powerex Corporation	SF		NA	NA	NA
9	Powerex Corporation	AD		NA	NA	NA
10	Provo City Corporation	LF		NA	NA	NA
11	Public Service Company of Colorado	SF		NA	NA	NA
12	Public Service Company of New Mexico	SF		NA	NA	NA
13	PUD No. 1 of Chelan County	SF		NA	NA	NA
14	PUD No. 1 of Douglas County	LF		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
4,354					125,820	125,820	1
12,754					196,398	196,398	2
					-36,073	-36,073	3
307,667				8,120,677	11,282	8,131,959	4
67,799				4,801,258		4,801,258	5
58,982				4,301,887		4,301,887	6
80				5,200		5,200	7
430,595				31,679,053		31,679,053	8
56					3,192	3,192	9
47				4,158		4,158	10
2,275,102				62,782,346		62,782,346	11
124,842				3,263,671		3,263,671	12
95,462				5,126,564	2,168	5,128,732	13
47,250				1,647,290		1,647,290	14
13,668,425	7,967,992	7,994,889	32,377,530	904,189,538	-269,132,964	667,434,104	

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 2018/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	PUD No. 1 of Douglas County	LU		NA	NA	NA
2	PUD No. 1 of Douglas County	AD		NA	NA	NA
3	PUD No. 1 of Douglas County	SF		NA	NA	NA
4	PUD No. 1 of Snohomish County	SF		NA	NA	NA
5	PUD No. 2 of Grant County	LU		NA	NA	NA
6	PUD No. 2 of Grant County	AD		NA	NA	NA
7	PUD No. 2 of Grant County	SF		NA	NA	NA
8	Puget Sound Energy, Inc.	SF		NA	NA	NA
9	Quichapa 1, LLC	LU		3	3	1
10	Quichapa 2, LLC	LU		3	3	1
11	Quichapa 3, LLC	LU		3	3	1
12	Rainbow Energy Marketing Corporation	SF		NA	NA	NA
13	Rock River I, LLC	LU		NA	NA	NA
14	Roseburg Forest Products Company	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 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.
179,942					2,302,403	2,302,403	1
					-61,266	-61,266	2
15,481				462,014	1,039	463,053	3
97,434				1,433,718		1,433,718	4
98,101					926,725	926,725	5
					392,816	392,816	6
125					4,234	4,234	7
129,985				4,043,249	11,889	4,055,138	8
8,053			240,206	280,408		520,614	9
7,957			238,805	277,077		515,882	10
7,964			240,118	277,314		517,432	11
1,200				33,840		33,840	12
138,698				4,921,006		4,921,006	13
53,951				2,232,934		2,232,934	14
13,668,425	7,967,992	7,994,889	32,377,530	904,189,538	-269,132,964	667,434,104	

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 2018/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	Roseburg LFG Energy, LLC	LU		NA	NA	NA
2	Roush Hydro Inc.	AD		NA	NA	NA
3	Sacramento Municipal Utility District	SF		NA	NA	NA
4	Salt River Project	SF		NA	NA	NA
5	Sand Ranch Windfarm, LLC	LU		NA	NA	NA
6	Santiam Water Control District	LU		0	0	0
7	Santiam Water Control District	AD		NA	NA	NA
8	Seattle City Light	SF		NA	NA	NA
9	Sempra Gas & Power Marketing, Llc	SF		NA	NA	NA
10	Sempra Gas & Power Marketing, Llc	AD		NA	NA	NA
11	Shell Energy North America (US), L.P.	SF		NA	NA	NA
12	Shell Energy North America (US), L.P.	AD		NA	NA	NA
13	Shiloh Warm Springs Ranch, LLC	LU		NA	NA	NA
14	Sierra Pacific Power 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.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
6,013				480,438		480,438	1
					-898	-898	2
2,000				52,000		52,000	3
241,516				11,094,412		11,094,412	4
25,553				1,963,830		1,963,830	5
1,372			12,496	174,084		186,580	6
					-28,920	-28,920	7
107,913				3,629,684	4,647	3,634,331	8
157,996				4,596,357		4,596,357	9
					-128	-128	10
334,895				16,976,049		16,976,049	11
					-704	-704	12
458				29,218		29,218	13
219				11,566	3,164	14,730	14
13,668,425	7,967,992	7,994,889	32,377,530	904,189,538	-269,132,964	667,434,104	

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 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Simplot Phosphates, LLC	LU		NA	NA	NA
2	Slate Creek Hydro Company, Inc.	LU		2	1	0
3	Solwatt, LLC	LU		NA	NA	NA
4	Southern California Edison Company	SF		NA	NA	NA
5	Spanish Fork Wind Park 2, LLC	LU		NA	NA	NA
6	Sprague Hydro LLC	LU		1	1	0
7	St. Anthony Hydro, LLC	LU		NA	NA	NA
8	Stahlbush Island Farms, Inc.	IU		NA	NA	NA
9	Stahlbush Island Farms, Inc.	AD		NA	NA	NA
10	SunE DB18, LLC	LU		3	3	1
11	SunE DB24, LLC	LU		3	3	1
12	SunE Solar XVII Project 1, LLC	LU		3	3	1
13	SunE Solar XVII Project 2, LLC	LU		3	3	1
14	SunE Solar XVII Project 3, LLC	LU		3	3	1
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
5				123		123	1
2,453			42,735	324,406		367,141	2
982				33,476		33,476	3
15				375		375	4
44,205				2,471,906		2,471,906	5
2,593			55,786	367,189		422,975	6
5,507				352,364		352,364	7
1,077				24,755		24,755	8
					5	5	9
7,653			374,814	425,493		800,307	10
7,207			165,298	250,965		416,263	11
7,455			402,553	380,213		782,766	12
7,336			402,648	374,153		776,801	13
7,115			222,852	247,755		470,607	14
13,668,425	7,967,992	7,994,889	32,377,530	904,189,538	-269,132,964	667,434,104	

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 2018/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	Sunny Bar Ranch LP	LU		NA	NA	NA
2	Sunnyside Cogeneration Associates	LU		52	54	43
3	Surprise Valley Electrification Corp.	LU		NA	NA	NA
4	Swalley Irrigation District	LU		NA	NA	NA
5	Sweetwater Solar LLC	LU		NA	NA	NA
6	Tacoma Power	SF		NA	NA	NA
7	Tata Chemicals (Soda Ash) Partners	LU		NA	NA	NA
8	Tenaska Power Services Co.	SF		NA	NA	NA
9	Tesoro Refining & Marketing Co LLC	LU		NA	NA	NA
10	Thayn Hydro LLC	LU		N/A	N/A	N/A
11	The Energy Authority, Inc.	SF		NA	NA	NA
12	Three Buttes Windpower, LLC	LU		NA	NA	NA
13	Three Peaks Power, LLC	LU		NA	NA	NA
14	Three Sisters Irrigation District	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)	
956				60,975		60,975	1
412,915				29,704,285		29,704,285	2
							3
2,273				177,342		177,342	4
841				33,932		33,932	5
65,999				5,205,800	1,841	5,207,641	6
5,678				197,364		197,364	7
22,478				1,497,911		1,497,911	8
12,531				243,609		243,609	9
3,139				134,233		134,233	10
46,731				1,866,151		1,866,151	11
309,188				19,692,671		19,692,671	12
226,299				9,599,028		9,599,028	13
2,155				120,546		120,546	14
13,668,425	7,967,992	7,994,889	32,377,530	904,189,538	-269,132,964	667,434,104	

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	Threemile Canyon Wind I, LLC	LU		NA	NA	NA
2	TMF Biofuels, LLC	LU		NA	NA	NA
3	TMF Biofuels, LLC	AD		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.	SF		NA	NA	NA
7	TransCanada Energy Sales Ltd.	SF		NA	NA	NA
8	Tri-State Generation and Transmission	LF		26	25	13
9	Tri-State Generation and Transmission	SF		NA	NA	NA
10	Tucson Electric Power Company	SF		NA	NA	NA
11	Tumbleweed Solar LLC	LU		NA	NA	NA
12	Tumbleweed Solar LLC	AD		NA	NA	NA
13	Turlock Irrigation District	SF		NA	NA	NA
14	U.S. Dept of the Interior	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)	
22,544				1,759,023		1,759,023	1
31,883				2,416,360		2,416,360	2
3,685					269,345	269,345	3
704				20,513		20,513	4
532,188				35,124,426	2,352,079	37,476,505	5
195,012				9,037,231		9,037,231	6
2,200				285,200		285,200	7
96,830			6,219,000	3,132,451		9,351,451	8
20,961				1,279,483	31	1,279,514	9
172,918				5,642,465		5,642,465	10
20,563				853,630		853,630	11
					-401	-401	12
9,066				565,440		565,440	13
23				1,590		1,590	14
13,668,425	7,967,992	7,994,889	32,377,530	904,189,538	-269,132,964	667,434,104	

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 2018/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	U.S. Air Force at Hill Air Force Base	LU		NA	NA	NA
2	UNS Electric, Inc.	SF		NA	NA	NA
3	US Magnesium LLC	LU		NA	NA	NA
4	US Magnesium LLC	AD		NA	NA	NA
5	Utah Associated Municipal Power System	LF		NA	NA	NA
6	Utah Associated Municipal Power System	SF		NA	NA	NA
7	Utah Municipal Power Agency	SF		185	180	43
8	Utah Red Hills Renewable Park, LLC	LU		NA	N/A	N/A
9	Utah Retail Solar Customers	LU		NA	NA	NA
10	Vitol Inc.	SF		NA	NA	NA
11	Wagon Trail, LLC	LU		NA	NA	NA
12	Ward Butte Windfarm, LLC	LU		NA	NA	NA
13	Weber County	LU		NA	NA	NA
14	Western Area Power Adm CO MO	SF		NA	NA	NA
	Total					

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
13,718				753,966		753,966	1
29,778				1,190,567		1,190,567	2
					5,477,029	5,477,029	3
					-30	-30	4
60,736				3,093,152		3,093,152	5
193				5,184		5,184	6
51,050			2,010,000	1,403,334	391,869	3,805,203	7
209,463				12,238,945		12,238,945	8
4,926				453,208		453,208	9
117,000				2,890,214		2,890,214	10
7,915				609,362		609,362	11
18,228				1,396,973		1,396,973	12
910				49,564		49,564	13
18,131				530,738	147	530,885	14
13,668,425	7,967,992	7,994,889	32,377,530	904,189,538	-269,132,964	667,434,104	

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Western Area Power Adm CO River	LF		NA	NA	NA
2	Wolverine Creek Energy, LLC	LU		NA	NA	NA
3	Woodline Solar, LLC	IU		NA	NA	NA
4	Woodline Solar, LLC	AD		NA	NA	NA
5	Yakima-Tieton Irrigation District	LU		2	1	1
6	CA Greenhouse Gas Allowance Purchases			NA	NA	NA
7	Net Power Cost Deferrals			NA	NA	NA
8	Netting - Bookouts			NA	NA	NA
9	Netting - Trading			NA	NA	NA
10	System Deviation			NA	NA	NA
11	Accrual			NA	NA	NA
12						
13	Power Exchanges:					
14	Arizona Public Service Company	EX	307	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)	
23,882				776,972		776,972	1
171,358				10,266,064		10,266,064	2
14,513				601,288		601,288	3
75					1,879	1,879	4
6,005			20,577	224,843		245,420	5
					2,154,523	2,154,523	6
					-43,809,576	-43,809,576	7
-8,985,630					-236,899,121	-236,899,121	8
					-2,786,566	-2,786,566	9
-7,406							10
					11,275,572	11,275,572	11
							12
							13
	569,755	571,392			-3,685,475	-3,685,475	14
13,668,425	7,967,992	7,994,889	32,377,530	904,189,538	-269,132,964	667,434,104	

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 2018/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	Avista Corporation	EX	382	NA	NA	NA
2	Bonneville Power Administration	EX	237	NA	NA	NA
3	Bonneville Power Administration	AD	237	NA	NA	NA
4	Bonneville Power Administration	EX	519	NA	NA	NA
5	Bonneville Power Administration	EX	T-BPA	NA	NA	NA
6	Bonneville Power Administration	AD	T-BPA	NA	NA	NA
7	California Independent System Operator	EX	T-12	NA	NA	NA
8	California Independent System Operator	EX	T-11	NA	NA	NA
9	California Independent System Operator	AD	T-12	NA	NA	NA
10	California Independent System Operator	AD	T-11	NA	NA	NA
11	Emerald People's Utility District	EX	351	NA	NA	NA
12	Eugene Water & Electric Board	EX	T-12	NA	NA	NA
13	Idaho Power Company	EX	708	NA	NA	NA
14	Idaho Power Company	EX	T-6	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)	
		1,708					1
	8,899	2,758			5,021	5,021	2
	-216	2,234			-12,867	-12,867	3
	94,865	82,633					4
	218,621	7,939			255,976	255,976	5
					-25	-25	6
	3,710,726	4,389,797			-84,386,188	-84,386,188	7
					17,248,769	17,248,769	8
					2,729,583	2,729,583	9
					-507,708	-507,708	10
		848			-21,192	-21,192	11
	19,954	20,358					12
	106,054	116,115					13
	10,602	2,000					14
13,668,425	7,967,992	7,994,889	32,377,530	904,189,538	-269,132,964	667,434,104	

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 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Los Angeles Dept. of Water and Power	EX	OV-1	NA	NA	NA
2	Milford Wind Corridor Phase I, LLC	EX	OV-1	NA	NA	NA
3	Milford Wind Corridor Phase II, LLC	EX	OV-1	NA	NA	NA
4	NorthWestern Corporation	EX	160	NA	NA	NA
5	Portland General Electric Company	EX	T-8	NA	NA	NA
6	Public Service Company of Colorado	AD	334	NA	NA	NA
7	Public Service Company of Colorado	EX	334	NA	NA	NA
8	PUD No. 1 of Cowlitz County	EX	442	NA	NA	NA
9	Seattle City Light	EX	554	NA	NA	NA
10	Western Area Power Administration	EX	LAS-4	NA	NA	NA
11	Western Area Power Administration	AD	LAS-4	NA	NA	NA
12	Imbalance Energy Accrual	EX	T-11	NA	NA	NA
13						
14						
	Total					

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
	4,450				329,854	329,854	1
		2,917			-203,174	-203,174	2
		1,533			-126,681	-126,681	3
	541						4
	4,289						5
	2,048						6
	1,314,000	1,312,284			5,400,000	5,400,000	7
	182,513	197,540					8
	374,911	342,873			2,267,819	2,267,819	9
	57,630	143,970			-479,209	-479,209	10
		-2,802			-197,661	-197,661	11
	1,288,350	798,792			13,104,330	13,104,330	12
							13
							14
13,668,425	7,967,992	7,994,889	32,377,530	904,189,538	-269,132,964	667,434,104	

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: a
Complete name is Arizona Electric Power Cooperative, Inc.

Schedule Page: 326 Line No.: 5 Column: b
Arizona Public Service Company - contract termination date: October 31, 2020.

Schedule Page: 326 Line No.: 7 Column: b
Settlement adjustment.

Schedule Page: 326 Line No.: 7 Column: l
Settlement adjustment.

Schedule Page: 326 Line No.: 8 Column: l
Reserve share.

Schedule Page: 326 Line No.: 9 Column: b
Settlement adjustment.

Schedule Page: 326 Line No.: 9 Column: l
Settlement adjustment.

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

Schedule Page: 326 Line No.: 14 Column: b
Settlement adjustment.

Schedule Page: 326 Line No.: 14 Column: l
Settlement adjustment.

Schedule Page: 326.1 Line No.: 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.: 8 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: Upon 30 days written notice.

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

Schedule Page: 326.1 Line No.: 12 Column: l
Reserve share.

Schedule Page: 326.1 Line No.: 13 Column: b
Settlement adjustment.

Schedule Page: 326.1 Line No.: 13 Column: l
Settlement adjustment.

Schedule Page: 326.2 Line No.: 8 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.: 9 Column: b
Settlement adjustment.

Schedule Page: 326.2 Line No.: 9 Column: l
Settlement adjustment.

Schedule Page: 326.2 Line No.: 11 Column: b
Settlement adjustment.

Schedule Page: 326.2 Line No.: 11 Column: l
Settlement adjustment.

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

City of Hurricane - contract termination date: August 31, 2022.

Schedule Page: 326.3 Line No.: 10 Column: b

Settlement adjustment.

Schedule Page: 326.3 Line No.: 10 Column: l

Settlement adjustment.

Schedule Page: 326.3 Line No.: 11 Column: l

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

Schedule Page: 326.3 Line No.: 12 Column: b

Settlement adjustment.

Schedule Page: 326.3 Line No.: 12 Column: l

Settlement adjustment.

Schedule Page: 326.3 Line No.: 13 Column: a

Complete name is City of Portland, Portland Water Bureau.

Schedule Page: 326.3 Line No.: 14 Column: b

Settlement adjustment.

Schedule Page: 326.3 Line No.: 14 Column: l

Settlement adjustment.

Schedule Page: 326.4 Line No.: 10 Column: b

Settlement adjustment.

Schedule Page: 326.4 Line No.: 10 Column: l

Settlement adjustment.

Schedule Page: 326.4 Line No.: 13 Column: a

Complete name is Deseret Generation and Transmission Co-operative.

Schedule Page: 326.4 Line No.: 13 Column: b

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

Schedule Page: 326.4 Line No.: 13 Column: l

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

Schedule Page: 326.5 Line No.: 6 Column: b

Settlement adjustment.

Schedule Page: 326.5 Line No.: 6 Column: l

Settlement adjustment.

Schedule Page: 326.5 Line No.: 11 Column: l

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

Schedule Page: 326.5 Line No.: 13 Column: b

Secondary, economy, renewable attributes and/or non-firm.

Schedule Page: 326.5 Line No.: 13 Column: l

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

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

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

Schedule Page: 326.6 Line No.: 8 Column: b

Settlement adjustment.

Schedule Page: 326.6 Line No.: 8 Column: l

Settlement adjustment.

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

Complete name is Fall River Rural Electric Cooperative, Inc.

Schedule Page: 326.6 Line No.: 14 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.7 Line No.: 2 Column: b

Flathead Electric Cooperative, Inc. - contract termination date: September 30, 2021.

Schedule Page: 326.7 Line No.: 3 Column: b
Settlement adjustment.

Schedule Page: 326.7 Line No.: 3 Column: l
Settlement adjustment.

Schedule Page: 326.7 Line No.: 8 Column: l
Fixed annual payment.

Schedule Page: 326.7 Line No.: 9 Column: b
Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.7 Line No.: 14 Column: l
Reserve share.

Schedule Page: 326.8 Line No.: 3 Column: a
Complete name is Hayward Paul Luckey and Joanne Luckey Revocable Trust of 2005.

Schedule Page: 326.8 Line No.: 4 Column: b
Secondary, economy, renewable attributes and/or non-firm.

Schedule Page: 326.8 Line No.: 5 Column: l
Reserve share.

Schedule Page: 326.8 Line No.: 9 Column: b
Settlement adjustment.

Schedule Page: 326.8 Line No.: 9 Column: l
Settlement adjustment.

Schedule Page: 326.9 Line No.: 1 Column: b
Settlement adjustment.

Schedule Page: 326.9 Line No.: 1 Column: l
Settlement adjustment.

Schedule Page: 326.9 Line No.: 2 Column: l
Fixed annual payment.

Schedule Page: 326.9 Line No.: 5 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.: 11 Column: b
Settlement adjustment.

Schedule Page: 326.9 Line No.: 11 Column: l
Settlement adjustment.

Schedule Page: 326.9 Line No.: 13 Column: b
Settlement adjustment.

Schedule Page: 326.9 Line No.: 13 Column: l
Settlement adjustment.

Schedule Page: 326.10 Line No.: 1 Column: l
Compensation for interruptible service and operating reserves.

Schedule Page: 326.10 Line No.: 2 Column: b
Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.10 Line No.: 4 Column: b
Settlement adjustment.

Schedule Page: 326.10 Line No.: 4 Column: l
Settlement adjustment.

Schedule Page: 326.10 Line No.: 8 Column: a
Complete name is Myron Jones, Nola Jones, Larry Oja and Christie Oja.

Schedule Page: 326.10 Line No.: 9 Column: l
Reserve share.

Schedule Page: 326.10 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: 326.10 Line No.: 11 Column: b

Settlement adjustment.

Schedule Page: 326.10 Line No.: 11 Column: l

Settlement adjustment.

Schedule Page: 326.11 Line No.: 1 Column: b

Settlement adjustment.

Schedule Page: 326.11 Line No.: 3 Column: b

Settlement adjustment.

Schedule Page: 326.11 Line No.: 3 Column: l

Settlement adjustment.

Schedule Page: 326.11 Line No.: 4 Column: l

Reserve share.

Schedule Page: 326.11 Line No.: 7 Column: b

Settlement adjustment.

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

Settlement adjustment.

Schedule Page: 326.11 Line No.: 9 Column: l

Ancillary services.

Schedule Page: 326.11 Line No.: 13 Column: b

Settlement adjustment.

Schedule Page: 326.11 Line No.: 13 Column: l

Settlement adjustment.

Schedule Page: 326.12 Line No.: 2 Column: b

Settlement adjustment.

Schedule Page: 326.12 Line No.: 2 Column: l

Settlement adjustment.

Schedule Page: 326.12 Line No.: 11 Column: l

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

Schedule Page: 326.13 Line No.: 1 Column: l

Line loss.

Schedule Page: 326.13 Line No.: 2 Column: b

Portland General Electric Company - contract termination date: When the Round Butte project no longer operates for power production purposes.

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

Operation expense plus amortization of unrecovered costs of Cove Project.

Schedule Page: 326.13 Line No.: 3 Column: b

Settlement adjustment.

Schedule Page: 326.13 Line No.: 3 Column: l

Settlement adjustment.

Schedule Page: 326.13 Line No.: 4 Column: l

Reserve share.

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

Secondary, economy, renewable attributes and/or non-firm.

Schedule Page: 326.13 Line No.: 9 Column: b

Settlement adjustment.

Schedule Page: 326.13 Line No.: 9 Column: l

Settlement adjustment.

Schedule Page: 326.13 Line No.: 10 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.13 Line No.: 13 Column: a

Complete name is Public Utility District No. 1 of Chelan County.

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

Reserve share.

Schedule Page: 326.13 Line No.: 14 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: 326.13 Line No.: 14 Column: b

Public Utility District No. 1 of Douglas County - Contract terminated on August 31, 2018.

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

Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.14 Line No.: 2 Column: b

Settlement adjustment.

Schedule Page: 326.14 Line No.: 2 Column: l

Settlement adjustment.

Schedule Page: 326.14 Line No.: 3 Column: l

Reserve share.

Schedule Page: 326.14 Line No.: 4 Column: a

Complete name is Public Utility District No. 1 of Snohomish County.

Schedule Page: 326.14 Line No.: 5 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: 326.14 Line No.: 5 Column: l

Operating expense, bond interest, amortization and taxes.

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.: 7 Column: l

Reserve share.

Schedule Page: 326.14 Line No.: 8 Column: l

Reserve share.

Schedule Page: 326.15 Line No.: 2 Column: b

Settlement adjustment.

Schedule Page: 326.15 Line No.: 2 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: 326.15 Line No.: 8 Column: l

Reserve share.

Schedule Page: 326.15 Line No.: 10 Column: b

Settlement adjustment.

Schedule Page: 326.15 Line No.: 10 Column: l

Settlement adjustment.

Schedule Page: 326.15 Line No.: 12 Column: b

Settlement adjustment.

Schedule Page: 326.15 Line No.: 12 Column: l

Settlement adjustment.

Schedule Page: 326.15 Line No.: 14 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: 326.15 Line No.: 14 Column: l

Reserve share.

Schedule Page: 326.16 Line No.: 9 Column: b
Settlement adjustment.

Schedule Page: 326.16 Line No.: 9 Column: l
Settlement adjustment.

Schedule Page: 326.17 Line No.: 6 Column: l
Reserve share.

Schedule Page: 326.17 Line No.: 9 Column: a
Complete name is Tesoro Refining & Marketing Company LLC.

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.: 5 Column: l
Non-generation agreement.

Schedule Page: 326.18 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: 326.18 Line No.: 8 Column: b
Tri-State Generation and Transmission Association, Inc. - contract termination date: December 31, 2020.

Schedule Page: 326.18 Line No.: 9 Column: l
Line loss.

Schedule Page: 326.18 Line No.: 12 Column: b
Settlement adjustment.

Schedule Page: 326.18 Line No.: 12 Column: l
Settlement adjustment.

Schedule Page: 326.18 Line No.: 14 Column: a
Complete name is U.S. Department of the Interior - Bureau of Land Management.

Schedule Page: 326.19 Line No.: 3 Column: b
US Magnesium LLC - contract termination date: December 31, 2019.

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

Schedule Page: 326.19 Line No.: 4 Column: b
Settlement adjustment.

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

Schedule Page: 326.19 Line No.: 5 Column: b
Utah Associated Municipal Power System - contract termination date: March 31, 2022.

Schedule Page: 326.19 Line No.: 7 Column: l
Costs related to the West Valley Tolling Agreement:

$ 54,818	Station service
337,051	CT run rate charge
$391,869	

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

Schedule Page: 326.20 Line No.: 1 Column: b
Western Area Power Administration - contract termination date: May 31, 2022.

Schedule Page: 326.20 Line No.: 4 Column: b
Settlement adjustment.

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

Schedule Page: 326.20 Line No.: 6 Column: l
Purchases of greenhouse gas allowances for compliance with the California Air Resources Board greenhouse gas cap-and-trade program.

Schedule Page: 326.20 Line No.: 7 Column: l
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 326.20 Line No.: 8 Column: l
Reflects transactions that did not physically settle.
Schedule Page: 326.20 Line No.: 9 Column: l
Reflects transactions that did not physically settle.
Schedule Page: 326.20 Line No.: 10 Column: g
Settlement and/or reserve removal of potential payment.
Schedule Page: 326.20 Line No.: 11 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: 326.20 Line No.: 14 Column: l
Exchange energy credit.
Schedule Page: 326.21 Line No.: 2 Column: l
Storage and exchange charges.
Schedule Page: 326.21 Line No.: 3 Column: b
Settlement adjustment.
Schedule Page: 326.21 Line No.: 3 Column: l
Settlement adjustment.
Schedule Page: 326.21 Line No.: 5 Column: l
Storage and exchange charges.
Schedule Page: 326.21 Line No.: 6 Column: b
Settlement adjustment.
Schedule Page: 326.21 Line No.: 6 Column: l
Settlement adjustment.
Schedule Page: 326.21 Line No.: 7 Column: l
Energy Imbalance Market ("EIM") participating resource settlements in EIM.
Schedule Page: 326.21 Line No.: 8 Column: l
EIM entity settlements in EIM.
Schedule Page: 326.21 Line No.: 9 Column: b
Settlement adjustment.
Schedule Page: 326.21 Line No.: 9 Column: l
Settlement adjustment.
Schedule Page: 326.21 Line No.: 10 Column: b
Settlement adjustment.
Schedule Page: 326.21 Line No.: 10 Column: l
Settlement adjustment.
Schedule Page: 326.21 Line No.: 11 Column: l
Exchange energy credit.
Schedule Page: 326.22 Line No.: 1 Column: l
Station service for third party wind project.
Schedule Page: 326.22 Line No.: 2 Column: l
Reimbursement for providing station service to third party wind project.
Schedule Page: 326.22 Line No.: 3 Column: l
Reimbursement for providing station service to third party wind project.
Schedule Page: 326.22 Line No.: 6 Column: b
Settlement adjustment.
Schedule Page: 326.22 Line No.: 7 Column: l
Exchange energy expense.
Schedule Page: 326.22 Line No.: 8 Column: a
Complete name is Public Utility District No. 1 of Cowlitz County.
Schedule Page: 326.22 Line No.: 9 Column: l
Exchange energy expense.

Schedule Page: 326.22 Line No.: 10 Column: l

Imbalance energy settlements between PacifiCorp merchant function and third party transmission providers.

Schedule Page: 326.22 Line No.: 11 Column: b

Settlement adjustment.

Schedule Page: 326.22 Line No.: 11 Column: l

Settlement adjustment.

Schedule Page: 326.22 Line No.: 12 Column: l

Imbalance energy settlements between PacifiCorp, the transmission provider and third party transmission 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 2018/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	3 Phase Renewables, LLC	Bonneville Power Administration	Oregon Direct Access	FNO
2	Arizona Public Service Company	Arizona Public Service Company		OS
3	Avangrid Renewables, LLC			NF
4	Avangrid Renewables, LLC			AD
5	Avangrid Renewables, LLC			SFP
6	Avangrid Renewables, LLC			AD
7	Avangrid Renewables, LLC	Avangrid Renewables, LLC		OS
8	Avangrid Renewables, LLC	Avangrid Renewables, LLC		AD
9	Avangrid Renewables, LLC	Exxon Mobil	Nevada Power Company	LFP
10	Avangrid Renewables, LLC	Exxon Mobil	Nevada Power Company	AD
11	Avangrid Renewables, LLC	Bonneville Power Administration	Oregon Direct Access	FNO
12	Avangrid Renewables, LLC	Avangrid Renewables, LLC		AD
13	Avista Corporation			NF
14	Basin Electric Power Cooperative, Inc.	Western Area Power Administration	Powder River Energy Corporation	FNO
15	Basin Electric Power Cooperative, Inc.	Western Area Power Administration	Powder River Energy Corporation	AD
16	Basin Electric Power Cooperative, Inc.	Western Area Power Administration	Powder River Energy Corporation	NF
17	Basin Electric Power Cooperative, Inc.	Western Area Power Administration	Powder River Energy Corporation	AD
18	Basin Electric Power Cooperative, Inc.	Western Area Power Administration	Powder River Energy Corporation	SFP
19	Basin Electric Power Cooperative, Inc.	Western Area Power Administration	Powder River Energy Corporation	AD
20	Black Hills/Colorado Electric Utility Company			NF
21	Black Hills/Colorado Electric Utility Company			AD
22	Black Hills/Colorado Electric Utility Company			SFP
23	Black Hills/Colorado Electric Utility Company			AD
24	Black Hills Corporation	PacifiCorp	Montana-Dakota Utilities	FNO
25	Black Hills Corporation	PacifiCorp	Montana-Dakota Utilities	AD
26	Black Hills Corporation	PacifiCorp	Black Hills Corporation	LFP
27	Black Hills Corporation	PacifiCorp	Black Hills Corporation	AD
28	Black Hills Corporation			NF
29	Black Hills Corporation			AD
30	Black Hills Corporation			SFP
31	Black Hills Corporation			AD
32	Black Hills Power Marketing			NF
33	Black Hills Power Marketing			AD
34	Black Hills Power Marketing			SFP
	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)	MegaWatt Hours Delivered (j)	Line No.
SA 876	Bonneville Power Adm	Various	1	85	85	1
RS 436		Borah/Brady Sub				2
SA 121	Various	Various		191,646	191,646	3
SA 121	Various	Various		25,174	25,174	4
SA 122	Various	Various		62,738	62,738	5
SA 122	Various	Various		8,246	8,246	6
SA 476						7
SA 476						8
SA 279	Trona Substation	Red Butte/Mona Sub	31	68,645	68,645	9
SA 279	Trona Substation	Red Butte/Mona Sub	31	9,433	9,433	10
SA 742	Ponderosa Substation	Various	31	242,578	242,578	11
SA 742	Ponderosa Substation	Various		21,310	21,310	12
SA 886	Various	Various		856	856	13
SA 505	Yellowtail Sub	Sheridan Substation	10	69,455	69,455	14
SA 505	Yellowtail Sub	Sheridan Substation		7,125	7,125	15
SA 607	Various	Various		128,235	128,235	16
SA 607	Various	Various		471	471	17
SA 606	Various	Various		37,472	37,472	18
SA 606	Various	Various		49	49	19
SA 563	Various	Various		2,622	2,622	20
SA 563	Various	Various				21
SA 562	Various	Various				22
SA 562	Various	Various				23
SA 347	Various	Sheridan Substation	52	255,967	255,967	24
SA 347	Various	Sheridan Substation		29,088	29,088	25
SA 67	Various	Wyodak Substation	52	80,393	80,393	26
SA 67	Various	Wyodak Substation	52	1,030	1,030	27
SA 768	Various	Various		8,852	8,852	28
SA 768	Various	Various		45	45	29
SA 767	Various	Various		38,046	38,046	30
SA 767	Various	Various				31
SA 43	Various	Various		4,101	4,101	32
SA 43	Various	Various		173	173	33
SA 714	Various	Various		1,677	1,677	34
			4,246	**16,159,593**	**16,047,747**	

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.
348		64	412	1
				2
	1,719,565	647,002	2,366,567	3
		202,208	202,208	4
	692,733	28,693	721,426	5
		152,053	152,053	6
		-18,755	-18,755	7
		-599,702	-599,702	8
919,866		38,218	958,084	9
		66,699	66,699	10
469,305		101,307	570,612	11
		233,847	233,847	12
	6,020	251	6,271	13
289,061		46,921	335,982	14
		76,901	76,901	15
	804,220	33,073	837,293	16
		-3,064	-3,064	17
	251,181	10,342	261,523	18
		196	196	19
	15,320	651	15,971	20
		-366	-366	21
	201	8	209	22
		243	243	23
1,185,985		54,243	1,240,228	24
		83,197	83,197	25
1,533,109		63,699	1,596,808	26
		483,824	483,824	27
	54,282	2,264	56,546	28
		-1,819	-1,819	29
	475,083	19,490	494,573	30
		-11,261	-11,261	31
	21,590	895	22,485	32
		209	209	33
	1,989	83	2,072	34
68,411,419	**17,764,076**	**30,441,391**	**116,616,886**	

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 2018/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	Black Hills Power Marketing			AD
2	Bonneville Power Administration			OS
3	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS
4	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
5	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	LFP
6	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
7	Bonneville Power Administration	Bonneville Power Administration	Umpqua Indian Utility Cooperative	FNO
8	Bonneville Power Administration	Bonneville Power Administration	Umpqua Indian Utility Cooperative	AD
9	Bonneville Power Administration	Bonneville Power Administration	Benton REA	FNO
10	Bonneville Power Administration	Bonneville Power Administration	Benton REA	AD
11	Bonneville Power Administration	Bonneville Power Administration	Umatilla Electric and Columbia	FNO
12	Bonneville Power Administration	Bonneville Power Administration	Umatilla Electric and Columbia	AD
13	Bonneville Power Administration	U.S. Bureau of Reclamation	Bonneville Power Administration	LFP
14	Bonneville Power Administration	U.S. Bureau of Reclamation	Bonneville Power Administration	AD
15	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS
16	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
17	Bonneville Power Administration	Bonneville Power Administration	Yakama Power	FNO
18	Bonneville Power Administration	Bonneville Power Administration	Yakama Power	AD
19	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	FNO
20	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
21	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	FNO
22	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
23	Bonneville Power Administration			NF
24	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
25	Bonneville Power Administration			SFP
26	Bonneville Power Administration			FNO
27	Bonneville Power Administration			AD
28	Bonneville Power Administration	Bonneville Power Administration	PUD No. 1 of Clark County	FNO
29	Bonneville Power Administration	Bonneville Power Administration	PUD No. 1 of Clark County	AD
30	Brookfield Energy Marketing LP			NF
31	Brookfield Energy Marketing LP			AD
32	Calpine Energy Solutions, LLC	Bonneville Power Administration	Oregon Direct Access	FNO
33	Calpine Energy Solutions, LLC	Bonneville Power Administration	Oregon Direct Access	AD
34	Cargill Power Markets, LLC			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 MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
SA 714	Various	Various				1
RS 369	Midpoint Substation	Summer Lake Sub				2
RS 237	Various	Various	357	1,112,760	1,112,760	3
RS 237	Various	Various	354	101,532	101,532	4
SA 656	Lost Creek Hydro Plt	Alvey Substation	58	183,005	183,005	5
SA 656	Lost Creek Hydro Plt	Alvey Substation	58	19,394	19,394	6
SA 229	Bonneville Power Adm	Gazley Substation	4	23,554	23,554	7
SA 229	Bonneville Power Adm	Gazley Substation		2,315	2,315	8
SA 539	Bonneville Power Adm	Tieton Substation	1	5,106	5,106	9
SA 539	Bonneville Power Adm	Tieton Substation		913	913	10
SA 538	McNary Substation	Hinkle Substation	1	770	770	11
SA 538	McNary Substation	Hinkle Substation	1	152	152	12
SA 179	USBR Green Springs	Bonneville Power Adm	19	66,264	66,264	13
SA 179	USBR Green Springs	Bonneville Power Adm		4,509	4,509	14
RS 368	Malin Substation	Malin Substation		663,088	663,088	15
RS 368	Malin Substation	Malin Substation		45,833	45,833	16
SA 328	Bonneville Power Adm		7	40,285	40,285	17
SA 328	Bonneville Power Adm			4,091	4,091	18
SA 827	Bonneville Power Adm	Neff Substation	1	463	463	19
SA 827	Bonneville Power Adm	Neff Substation		196	196	20
SA 746	Goshen Substation	Various	168	1,223,570	1,223,570	21
SA 746	Goshen Substation	Various		155,757	155,757	22
SA 44	Various	Various		177,315	177,315	23
SA 44	Various	Various				24
SA 720	Various	Various		177,530	177,530	25
SA 747	Goshen Substation	Various	81	506,725	506,725	26
SA 747	Goshen Substation	Various		53,964	53,964	27
SA 735	Cardwell-Merwin		15	110,858	110,858	28
SA 735	Cardwell-Merwin			16,058	16,058	29
SA 757	Various	Various		56,449	56,449	30
SA 757	Various	Various		355	355	31
SA 299	Bonneville Power Adm	Various	26	143,851	143,851	32
SA 299	Bonneville Power Adm	Various		11,871	11,871	33
SA 263	Various	Various				34
			4,246	**16,159,593**	**16,047,747**	

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.
		10,193	10,193	1
				2
4,075,515		-24,358	4,051,157	3
		366,404	366,404	4
1,717,083		15,923	1,733,006	5
		119,324	119,324	6
97,838		152,265	250,103	7
		103,587	103,587	8
20,615		2,891	23,506	9
		6,362	6,362	10
4,601		519	5,120	11
		993	993	12
551,919		4,804	556,723	13
		38,764	38,764	14
		232,452	232,452	15
		21,132	21,132	16
190,211		125,098	315,309	17
		54,194	54,194	18
633		242	875	19
		1,322	1,322	20
5,571,905		1,263,789	6,835,694	21
		685,998	685,998	22
	1,219,910	50,354	1,270,264	23
		-1,520	-1,520	24
	325,387	13,692	339,079	25
2,217,710		377,332	2,595,042	26
		1,599,069	1,599,069	27
575,381		76,658	652,039	28
		165,941	165,941	29
	287,454	12,039	299,493	30
		2,016	2,016	31
351,655		68,888	420,543	32
		116,555	116,555	33
		-18,123	-18,123	34
68,411,419	**17,764,076**	**30,441,391**	**116,616,886**	

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 2018/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	City of Anaheim			AD
2	City of Anaheim			SFP
3	City of Anaheim			AD
4	City of Roseville	City of Roseville	City of Roseville	LFP
5	Clatskanie People's Utility District	Clatskanie People's Utility Distr	Clatskanie People's Utility Distr	LFP
6	Clatskanie People's Utility District	Clatskanie People's Utility Distr	Clatskanie People's Utility Distr	AD
7	Deseret Generation and Transmission	Deseret Gen and Trans	Deseret Gen and Trans	OS
8	Deseret Generation and Transmission	Deseret Gen and Trans	Deseret Gen and Trans	AD
9	Deseret Generation and Transmission			NF
10	Deseret Generation and Transmission			AD
11	Eagle Energy Partners I LP			AD
12	Energy Keepers, Inc.			NF
13	Eugene Water & Electric Board	NextEra Energy Resources, LLC		LFP
14	Eugene Water & Electric Board	NextEra Energy Resources, LLC	PUD No. 2 of Grant County	AD
15	Eugene Water & Electric Board	NextEra Energy Resources, LLC		SFP
16	Enel Cove Fort, LLC	Enel Cove Fort, LLC		AD
17	Evergreen Biopower LLC	NextEra Energy Resources, LLC		LFP
18	Exelon Generation Company, LLC	Bonneville Power Administration	Oregon Direct Access	FNO
19	Exelon Generation Company, LLC	Bonneville Power Administration	Oregon Direct Access	AD
20	Exelon Generation Company, LLC			NF
21	Exelon Generation Company, LLC			AD
22	Exelon Generation Company, LLC			NF
23	Fall River Rural Electric Cooperative, Inc.	Marysville Hydro Partners	Idaho Power Company	OS
24	Fall River Rural Electric Cooperative, Inc.	Marysville Hydro Partners	Idaho Power Company	AD
25	Foote Creek III, LLC	Foote Creek III, LLC	PacifiCorp	OS
26	Foote Creek III, LLC	Foote Creek III, LLC	PacifiCorp	AD
27	Idaho Power Company	Exxon Mobil	Nevada Power Company	LFP
28	Idaho Power Company	Exxon Mobil	Nevada Power Company	AD
29	Idaho Power Company			NF
30	Idaho Power Company			AD
31	JP Morgan Ventures Energy Corporation			AD
32	Los Angeles Department of Water & Power			AD
33	Los Angeles Department of Water & Power			SFP
34	Macquarie Energy LLC			NF
	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.
SA 798	Various	Various		4,229	4,229	1
SA 797	Various	Various		2,419	2,419	2
SA 797	Various	Various		19,908	19,908	3
SA 881	Malin 500 Substation	Round Mountain Sub	52			4
SA 899	Troutdale Substation	Troutdale Substation	19	126,561	126,561	5
SA 899	Troutdale Substation	Troutdale Substation	19	16,723	16,723	6
RS 280	Various	Various	135	848,231	848,231	7
RS 280	Various	Various		44,190	44,190	8
SA 156	Various	Various		3,064	3,064	9
SA 156	Various	Various		3,804	3,804	10
SA 569	Various	Various				11
SA 569	Various	Various		388	388	12
SA 780	Various	Various	26			13
SA 780	Various	Various				14
SA 719	Various	Various				15
SA 711	Enel Cove Fort, LLC	Red Butte Substation				16
SA 874	Various	Various		43,670	43,670	17
SA 847	Bonneville Power Adm	Various	1	4,411	4,411	18
SA 847	Bonneville Power Adm	Various		41	41	19
SA 759	Various	Various		619	619	20
SA 759	Various	Various				21
SA 760	Various	Various				22
RS 322	Targhee Substation	Goshen Substation				23
RS 322	Targhee Substation	Goshen Substation				24
SA 761	Foote Creek Sub	Various				25
SA 761	Foote Creek Sub	Various				26
SA 212	Trona Substation	Red Butte/Mona Sub	78	1,765	1,765	27
SA 212	Trona Substation	Red Butte/Mona Sub				28
SA 725	Various	Various		2,479	2,479	29
SA 725	Various	Various				30
SA 335	Various	Various				31
SA 142	Various	Various				32
SA 143	Various	Various		7,121	7,121	33
SA 755	Various	Various		22,934	22,934	34
			4,246	**16,159,593**	**16,047,747**	

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.
		31,118	31,118	1
	14,346	601	14,947	2
		110,407	110,407	3
1,107,191		32,022	1,139,213	4
1,173,516		48,673	1,222,189	5
		306,852	306,852	6
2,558,618		1,129,271	3,687,889	7
		-199,806	-199,806	8
	20,486	1,103	21,589	9
		26,058	26,058	10
		-59	-59	11
	2,851	119	2,970	12
		217,914	217,914	13
		167,790	167,790	14
		580,506	580,506	15
		-1,219	-1,219	16
306,623		43,250	349,873	17
10,028		2,568	12,596	18
		117	117	19
	122,817	1,343,067	1,465,884	20
		-130,288	-130,288	21
	-312		-312	22
		138,699	138,699	23
		12,609	12,609	24
		62,312	62,312	25
		10,464	10,464	26
1,045,190		42,872	1,088,062	27
		73,213	73,213	28
	24,814	1,045	25,859	29
		-10,171	-10,171	30
		-19,857	-19,857	31
		-1,386	-1,386	32
	47,055	1,966	49,021	33
	216,779	8,927	225,706	34
68,411,419	**17,764,076**	**30,441,391**	**116,616,886**	

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	Macquarie Energy LLC			AD
2	Macquarie Energy LLC			SFP
3	MAG Energy Solutions, Inc.			NF
4	Moon Lake Electric Association	Moon Lake Electric Association	Moon Lake Electric Association	OS
5	Moon Lake Electric Association	Moon Lake Electric Association	Moon Lake Electric Association	AD
6	Morgan Stanley Capital Group, Inc.			NF
7	Morgan Stanley Capital Group, Inc.			AD
8	Morgan Stanley Capital Group, Inc.			SFP
9	Municipal Energy Agency of Nebraska			NF
10	Municipal Energy Agency of Nebraska			AD
11	Municipal Energy Agency of Nebraska			SFP
12	Navajo Tribal Utility Authority	Navajo Tribal Utility Authority	Navajo Tribal Utility Authority	FNO
13	Nevada Power Company			NF
14	Nevada Power Company			AD
15	Nevada Power Company			SFP
16	NextEra Energy Resources, LLC	NextEra Energy Resources, LLC	PUD No. 2 of Grant County	LFP
17	NextEra Energy Resources, LLC	NextEra Energy Resources, LLC	PUD No. 2 of Grant County	AD
18	NextEra Energy Resources, LLC			NF
19	NextEra Energy Resources, LLC			AD
20	Pacific Gas & Electric Company			OS
21	Pacific Gas & Electric Company			NF
22	Pacific Gas & Electric Company			AD
23	Portland General Electric Company			OS
24	Portland General Electric Company			AD
25	Powder River Energy Corporation	Western Area Power Administration	Sheridan-Johnson Rural Elect.	OS
26	Powder River Energy Corporation	Western Area Power Administration	Sheridan-Johnson Rural Elect.	AD
27	Powerex Corporation	Bonneville Power Administration	CAISO	LFP
28	Powerex Corporation	Bonneville Power Administration	CAISO	AD
29	Powerex Corporation	Powerex Corporation	CAISO	LFP
30	Powerex Corporation	Powerex Corporation	CAISO	AD
31	Powerex Corporation	Powerex Corporation	CAISO	LFP
32	Powerex Corporation	Powerex Corporation	CAISO	AD
33	Powerex Corporation	Powerex Corporation	CAISO	LFP
34	Powerex Corporation	Powerex Corporation	CAISO	AD
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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.
SA 755	Various	Various		212	212	1
SA 754	Various	Various		1,056	1,056	2
SA 903	Various	Various		6	6	3
RS 302	Duchesne	Duchesne		17,177	17,177	4
RS 302	Duchesne	Duchesne		1,432	1,432	5
SA 157	Various	Various		911,756	911,756	6
SA 157	Various	Various		2,274	2,274	7
SA 160	Various	Various		8,316	8,316	8
SA 307	Various	Various		2,921	2,921	9
SA 307	Various	Various		20	20	10
SA 307	Various	Various		500	500	11
SA 894	Four Corners	Pinto-Four Corners	1	5,335	5,335	12
SA 455	Various	Various		7,858	7,858	13
SA 455	Various	Various				14
SA 454	Various	Various		90,574	90,574	15
SA 733	Wallula Substation	Wala-MIDC path	103	39,872	39,872	16
SA 733	Wallula Substation	Wala-MIDC path	103			17
SA 236	Various	Various		20	20	18
SA 236	Various	Various				19
RS 607						20
SA 338	Various	Various		814	814	21
SA 338	Various	Various				22
RS 137	Various	Various				23
SA 8	Various	Various				24
RS 704	Various	Buffalo Substation				25
RS 704	Various	Buffalo Substation				26
SA 169	Bonneville Power Adm	CRAG View Substation	83	426,048	426,048	27
SA 169	Bonneville Power Adm	CRAG View Substation	83	35,353	35,353	28
SA 700	Malin 500 Substation	Round Mountain Sub	67			29
SA 700	Malin 500 Substation	Round Mountain Sub	67			30
SA 701	Malin 500 Substation	Round Mountain Sub	67			31
SA 701	Malin 500 Substation	Round Mountain Sub	67			32
SA 702	Malin 500 Substation	Round Mountain Sub	66			33
SA 702	Malin 500 Substation	Round Mountain Sub	66			34
			4,246	**16,159,593**	**16,047,747**	

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.
		-491	-491	1
	10,179	416	10,595	2
	48	2	50	3
		17,655	17,655	4
		1,605	1,605	5
	4,857,423	201,503	5,058,926	6
		-21,979	-21,979	7
	67,314	2,764	70,078	8
	17,696	739	18,435	9
		151	151	10
	2,683	111	2,794	11
23,634		4,073	27,707	12
	6,148	3,352	9,500	13
		-1,035	-1,035	14
	482,123	19,884	502,007	15
2,004,216		740,421	2,744,637	16
		369,719	369,719	17
	242,638	10,044	252,682	18
		1,813	1,813	19
		149,118	149,118	20
	6,958	291	7,249	21
		-263	-263	22
		3,314	3,314	23
		-2,093	-2,093	24
		-730	-730	25
		32	32	26
2,452,976		101,918	2,554,894	27
		500,838	500,838	28
2,935,586		71,552	3,007,138	29
		604,415	604,415	30
2,935,586		71,552	3,007,138	31
		604,415	604,415	32
2,935,586		71,552	3,007,138	33
		598,279	598,279	34
68,411,419	**17,764,076**	**30,441,391**	**116,616,886**	

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 2018/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	Powerex Corporation	Powerex Corporation	CAISO	LFP
2	Powerex Corporation	Powerex Corporation	CAISO	AD
3	Powerex Corporation	Powerex Corporation	CAISO	LFP
4	Powerex Corporation	Powerex Corporation	CAISO	AD
5	Powerex Corporation			NF
6	Powerex Corporation			AD
7	Powerex Corporation			SFP
8	Public Service Company of Colorado			NF
9	Public Service Company of New Mexico			AD
10	Puget Sound Energy, Inc.			AD
11	PUD No. 1 of Cowlitz County	PUD No. 1 of Cowlitz County	Bonneville Power Administration	OS
12	PUD No. 1 of Cowlitz County	PUD No. 1 of Cowlitz County	Bonneville Power Administration	AD
13	Rainbow Energy Marketing Corporation			NF
14	Rainbow Energy Marketing Corporation			AD
15	Sacramento Municipal Utility District	Sacramento Municipal Utility Dist	Sacramento Municipal Utility Dist	LFP
16	Sacramento Municipal Utility District	Sacramento Municipal Utility Dist	Sacramento Municipal Utility Dist	AD
17	Salt River Project	Salt River Project	Salt River Project	LFP
18	Salt River Project	Salt River Project	Salt River Project	AD
19	Salt River Project			NF
20	Salt River Project			AD
21	Seattle City Light			AD
22	Shell Energy North America (US), L.P.	NextEra Energy Resources, LLC	PUD No. 2 of Grant County	LFP
23	Shell Energy North America (US), L.P.	NextEra Energy Resources, LLC	PUD No. 2 of Grant County	AD
24	Shell Energy North America (US), L.P.			NF
25	Shell Energy North America (US), L.P.			AD
26	Shell Energy North America (US), L.P.			SFP
27	Shell Energy North America (US), L.P.			AD
28	Sierra Pacific Power Company			OS
29	Sierra Pacific Power Company			AD
30	Sierra Pacific Power Company			AD
31	Simplot Phosphates, LLC	Simplot Phosphates, LLC	Simplot Phosphates, LLC	OS
32	Simplot Phosphates, LLC	Simplot Phosphates, LLC	Simplot Phosphates, LLC	AD
33	Southern California Edison Company			OS
34	Southern California Edison Company			NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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.
SA 748	Malin 500 Substation	Round Mountain Sub	50			1
SA 748	Malin 500 Substation	Round Mountain Sub	50			2
SA 749	Malin 500 Substation	Round Mountain Sub	150			3
SA 749	Malin 500 Substation	Round Mountain Sub	50			4
SA 47	Various	Various		114,423	114,423	5
SA 47	Various	Various		1,589	1,589	6
SA 151	Various	Various		63,509	63,509	7
SA 664	Various	Various				8
SA 665	Various	Various				9
SA 693	Various	Various				10
RS 234	Swift Unit No. 2	Woodland Substation				11
RS 234	Swift Unit No. 2	Woodland Substation				12
SA 316	Various	Various		21,087	21,087	13
SA 316	Various	Various				14
SA 863	Malin Substation	Malin Substation	31	100,013	100,013	15
SA 863	Malin Substation	Malin Substation	31	10,257	10,257	16
SA 809	Enel Cove Fort	Red Butte Substation	26	136,034	136,034	17
SA 809	Enel Cove Fort	Red Butte Substation	26	16,676	16,676	18
SA 557	Various	Various		33	33	19
SA 557	Various	Various				20
SA 289	Wallula substation	Wallula substation				21
SA 791	Wallula Substation	Wala-MIDC path		89,587	89,587	22
SA 791	Wallula Substation	Wala-MIDC path		8,469	8,469	23
SA 23	Various	Various		260,863	260,863	24
SA 23	Various	Various		4,373	4,373	25
SA 162	Various	Various		64,581	64,581	26
SA 162	Various	Various		159	159	27
RS 674	Sigurd Substation	Utah-Nevada Border				28
RS 674	Sigurd Substation	Utah-Nevada Border				29
SA 732	Various	Various				30
						31
						32
RS 298	Sigurd-Glen Canyon	Pinto-Four Corners				33
SA 642	Various	Various		25,680	25,680	34
			4,246	**16,159,593**	**16,047,747**	

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.
1,467,794		35,776	1,503,570	1
		321,843	321,843	2
4,403,380		107,328	4,510,708	3
		965,529	965,529	4
	515,403	21,541	536,944	5
		-124,889	-124,889	6
	306,158	12,587	318,745	7
	24	-80	-56	8
		-2	-2	9
		-159	-159	10
		160,583	160,583	11
		14,318	14,318	12
	124,630	5,149	129,779	13
		-1,922	-1,922	14
582,597		24,207	606,804	15
		152,759	152,759	16
766,570		31,848	798,418	17
		169,882	169,882	18
	1,153	49	1,202	19
		-1,601	-1,601	20
		-273	-273	21
				22
				23
	1,507,090	641,045	2,148,135	24
		16,486	16,486	25
	312,499	12,787	325,286	26
		1,509	1,509	27
		33,147	33,147	28
		3,013	3,013	29
		-1,545	-1,545	30
		13,605	13,605	31
		3,784	3,784	32
		149,118	149,118	33
	2,496,834	1,077,648	3,574,482	34
68,411,419	**17,764,076**	**30,441,391**	**116,616,886**	

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	Southern California Edison Company			AD
2	Southern California Public Power Authority	Powerex Corporation	Southern California Public Power	NF
3	Southern California Public Power Authority	Powerex Corporation	Southern California Public Power	AD
4	State of South Dakota	Western Area Power Administration	Black Hills Corporation	LFP
5	State of South Dakota	Western Area Power Administration	Black Hills Corporation	AD
6	Talen Energy Marketing, LLC			AD
7	Tenaska Power Services Co.			NF
8	Tenaska Power Services Co.			AD
9	Tenaska Power Services Co.			SFP
10	The Energy Authority, Inc.			NF
11	The Energy Authority, Inc.			AD
12	Thermo No. 1 BE-01, LLC	Thermo Geothermal Project		LFP
13	Thermo No. 1 BE-01, LLC	Thermo Geothermal Project		AD
14	TransAlta Energy Marketing (U.S.) Inc.			NF
15	TransAlta Energy Marketing (U.S.) Inc.			AD
16	TransAlta Energy Marketing (U.S.) Inc.			SFP
17	Tri-State Geneneration and Transmission		Tri-State Gen and Trans	FNO
18	Tri-State Geneneration and Transmission		Tri-State Gen and Trans	AD
19	Tri-State Geneneration and Transmission			NF
20	Tri-State Geneneration and Transmission			AD
21	Tucson Power Company			AD
22	U.S. Bureau of Reclamation	Bonneville Power Administration	U.S. Bureau of Reclamation	FNO
23	U.S. Bureau of Reclamation	Bonneville Power Administration	U.S. Bureau of Reclamation	AD
24	U.S. Bureau of Reclamation	Western Area Power Administration	Weber Basin Water Conserv.	OS
25	U.S. Bureau of Reclamation	Western Area Power Administration	Weber Basin Water Conserv.	AD
26	U.S. Bureau of Reclamation	Bonneville Power Administration	Crooked River Irrigation District	OS
27	Utah Associated Municipal Power Systems	Utah Associated Municipal Power	Utah Associated Municipal Power	OS
28	Utah Associated Municipal Power Systems	Utah Associated Municipal Power	Utah Associated Municipal Power	AD
29	Utah Associated Municipal Power Systems			NF
30	Utah Associated Municipal Power Systems			AD
31	Utah Associated Municipal Power Systems			SFP
32	Utah Municipal Power Agency	Utah Municipal Power Agency	Utah Municipal Power Agency	OS
33	Utah Municipal Power Agency	Utah Municipal Power Agency	Utah Municipal Power Agency	AD
34	Warm Springs Power Enterprises	Warm Springs Power Enterprises	PGE	OS
	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.
SA 642	Various	Various		1,488	1,488	1
SA 629	Tieton Substation	Various		32	32	2
SA 629	Tieton Substation	Various				3
SA 779	Yellowtail Sub	Wyodak Substation	4	15,686	15,686	4
SA 779	Yellowtail Sub	Wyodak Substation	4	1,750	1,750	5
SA 255	Various	Various				6
SA 125	Various	Various		15,467	15,467	7
SA 125	Various	Various		410	410	8
SA 126	Various	Various		3,474	3,474	9
SA 310	Various	Various		3,502	3,502	10
SA 310	Various	Various		500	500	11
SA 568	South Milford Sub	Mona Substation	11	58,521	58,521	12
SA 568	South Milford Sub	Mona Substation	11	6,299	6,299	13
SA 127	Various	Various		43,363	43,363	14
SA 127	Various	Various				15
SA 127	Various	Various		507	507	16
SA 628	Dave Johnston Sub	Thermopolis Sub	16	118,688	118,688	17
SA 628	Dave Johnston Sub	Thermopolis Sub		10,638	10,638	18
SA 33	Various	Various		72	72	19
SA 33	Various	Various				20
SA 180	Various	Various				21
SA 506	Walla Walla Sub	Burbank Pumps	1	2,484	2,484	22
SA 506	Walla Walla Sub	Burbank Pumps		5	5	23
RS 286	Various	Various		27,685	27,685	24
RS 286	Various	Various		937	937	25
RS 67	Redmond Substation	Crooked River Pumps		10,029	10,029	26
RS 297	Various	Various	792	3,034,539	3,034,539	27
RS 297	Various	Various		248,981	248,981	28
SA 9	Various	Various		21	21	29
SA 9	Various	Various		58	58	30
SA 722	Various	Various		400	400	31
RS 637	Various	Various	145	667,838	667,838	32
RS 637	Various	Various		52,925	52,925	33
RS 591	Pelton Reregulating	Round Butte Sub		54,889	54,889	34
			4,246	**16,159,593**	**16,047,747**	

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.
		75,528	75,528	1
		36,810	36,810	2
		-1,484	-1,484	3
122,649		5,096	127,745	4
		24,734	24,734	5
		-2,222	-2,222	6
	111,504	262,524	374,028	7
		-10,456	-10,456	8
	25,266	1,054	26,320	9
	21,673	895	22,568	10
		1,527	1,527	11
337,298		43,458	380,756	12
		71,177	71,177	13
	273,826	11,390	285,216	14
		-7,040	-7,040	15
	4,467	19,171	23,638	16
467,461		54,990	522,451	17
		111,567	111,567	18
	4,748	193	4,941	19
		-3,008	-3,008	20
		-51	-51	21
9,369		11,788	21,157	22
		711	711	23
		27,685	27,685	24
		937	937	25
10,538			10,538	26
15,712,064		2,377,654	18,089,718	27
		2,296,311	2,296,311	28
	110	4	114	29
		416	416	30
	3,217	130	3,347	31
2,859,672		378,727	3,238,399	32
		451,154	451,154	33
		109,725	109,725	34
68,411,419	**17,764,076**	**30,441,391**	**116,616,886**	

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 2018/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	AD
2	Westar Energy, Inc.			NF
3	Western Area Power Administration	Western Area Power Administration		OS
4	Western Area Power Administration	Western Area Power Administration		AD
5	Western Area Power Administration	Western Area Power Administration		OS
6	Western Area Power Administration	Western Area Power Administration		AD
7	Western Area Power Administration	Western Area Power Administration		OS
8	Western Area Power Administration	Western Area Power Administration	Western Area Power Administration	FNO
9	Western Area Power Administration	Western Area Power Adm CO River	Western Area Power Administration	AD
10	Western Area Power Adm CO River	Western Area Power Adm CO River		NF
11	Western Area Power Adm CO River	Western Area Power Adm CO River		AD
12	Western Area Power Adm CO MO	Western Area Power Adm CO River		NF
13	Accrual			
14				
15				
16				
17				
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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.
RS 591	Pelton Reregulating	Round Butte Sub		7,895	7,895	1
SA 813	Various	Various		3,379	3,379	2
RS 262	Various	Various	330	1,648,928	1,549,991	3
RS 262	Various	Various		169,375	162,424	4
RS 263	Various	Various		43,314	40,749	5
RS 263	Various	Various		4,111	3,864	6
RS 684	Dave Johnston Sub	Various				7
SA 175	Wyoming Distribution	Wyoming Distribution	4	13,450	13,450	8
SA 175	Various	Wyoming Distribution		6	6	9
SA 132	Various	Various		325	325	10
SA 132	Various	Various				11
SA 724	Various	Various		1,510	1,510	12
				60,633	57,487	13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			4,246	**16,159,593**	**16,047,747**	

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 2018/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
		9,975	9,975	1
	25,664	1,051	26,715	2
2,358,272		550,000	2,908,272	3
		264,317	264,317	4
		44,180	44,180	5
		4,047	4,047	6
				7
52,265		54,836	107,101	8
		3,055	3,055	9
	2,802	118	2,920	10
		-790	-790	11
	10,027	409	10,436	12
		3,801,921	3,801,921	13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
68,411,419	**17,764,076**	**30,441,391**	**116,616,886**	

Schedule Page: 328 Line No.: 1 Column: d

Transmission service under the Open Access Transmission Tariff (Service Agreement 876). 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 Line No.: 1 Column: f

This footnote applies to all occurrences of "Bonneville Power Adm" on pages 328-330. Complete name is Bonneville Power Administration.

Schedule Page: 328 Line No.: 1 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

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

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

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

Glenn Canyon/Four Corners Substation

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

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. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

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

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 6 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 6 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 6 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 6 Column: m
2017 transmission and ancillary services.

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
Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328 Line No.: 8 Column: c
Avangrid Renewables, LLC and Utah Associated Municipal Power Systems

Schedule Page: 328 Line No.: 8 Column: d
Ancillary services under the Open Access Transmission Tariff (1st Revised Service Agreement 476) in effect until superseded.

Schedule Page: 328 Line No.: 8 Column: f
Long Hollow, WY Switching Station

Schedule Page: 328 Line No.: 8 Column: g
Long Hollow, WY Switching Station

Schedule Page: 328 Line No.: 8 Column: m
2017 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328 Line No.: 9 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.: 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
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 10 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.: 10 Column: m
2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328 Line No.: 11 Column: d
Network transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 742) terminating no earlier than 12-months from notice by the customer.

Schedule Page: 328 Line No.: 11 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.: 12 Column: c

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

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

Network transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 742) terminating no earlier than 12-months from notice by the customer.

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

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328 Line No.: 13 Column: b

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

Schedule Page: 328 Line No.: 13 Column: c

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

Schedule Page: 328 Line No.: 13 Column: d

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

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 14 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.: 14 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.: 15 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.: 15 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

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

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

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

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

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328 Line No.: 18 Column: c

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

Schedule Page: 328 Line No.: 18 Column: d

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

Schedule Page: 328 Line No.: 18 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control

service.

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

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328 Line No.: 20 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.: 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

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.: 21 Column: b

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

Schedule Page: 328 Line No.: 21 Column: c

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

Schedule Page: 328 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 Line No.: 21 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328 Line No.: 22 Column: b

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

Schedule Page: 328 Line No.: 22 Column: c

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

Schedule Page: 328 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 Line No.: 22 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.: 23 Column: b

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

Schedule Page: 328 Line No.: 23 Column: c

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

Schedule Page: 328 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 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

Network transmission service under the Open Access Transmission Tariff (3rd Revised

Service Agreement 347) terminating on December 31, 2023.

Schedule Page: 328 Line No.: 24 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 25 Column: d

Network transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 347) terminating on December 31, 2023.

Schedule Page: 328 Line No.: 25 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328 Line No.: 26 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.: 26 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.: 27 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.: 27 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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

2017 annual transmission services true-up refunds and/or surcharge.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 31 Column: b

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

Schedule Page: 328 Line No.: 31 Column: c

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

Schedule Page: 328 Line No.: 31 Column: d

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

Schedule Page: 328 Line No.: 31 Column: m

2017 transmission and ancillary services.

Schedule Page: 328 Line No.: 32 Column: b

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

Schedule Page: 328 Line No.: 32 Column: c

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

Schedule Page: 328 Line No.: 32 Column: d

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

Schedule Page: 328 Line No.: 32 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 33 Column: b

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

Schedule Page: 328 Line No.: 33 Column: c

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

Schedule Page: 328 Line No.: 33 Column: d

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

Schedule Page: 328 Line No.: 33 Column: m

2017 transmission and ancillary services.

Schedule Page: 328 Line No.: 34 Column: b

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

Schedule Page: 328 Line No.: 34 Column: c

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

Schedule Page: 328 Line No.: 34 Column: d

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

Schedule Page: 328 Line No.: 34 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 1 Column: b

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

Schedule Page: 328.1 Line No.: 1 Column: c

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

Schedule Page: 328.1 Line No.: 1 Column: d

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

Schedule Page: 328.1 Line No.: 1 Column: m

2017 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 2 Column: b

Capacity exchanged and operated by each transmission provider with no receipt or delivery of energy.

Schedule Page: 328.1 Line No.: 2 Column: c

Capacity exchanged and operated by each transmission provider with no receipt or delivery of energy.

Schedule Page: 328.1 Line No.: 2 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: 328.1 Line No.: 3 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 terminate 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: 328.1 Line No.: 3 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge.

Schedule Page: 328.1 Line No.: 4 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 terminate 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: 328.1 Line No.: 4 Column: m

2017 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 5 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.: 5 Column: m

Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 6 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.: 6 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.1 Line No.: 7 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (9th Revised Service Agreement 229) terminating on September 30, 2028.

Schedule Page: 328.1 Line No.: 7 Column: m

Distribution voltage service charge. Primary delivery service. Regulation and frequency response service. Reactive supply and voltage control service. Operating reserve - spinning reserve service. Operating Reserve - supplemental reserve service.

Schedule Page: 328.1 Line No.: 8 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (9th Revised Service Agreement 229) terminating on September 30, 2028.

Schedule Page: 328.1 Line No.: 8 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.1 Line No.: 9 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.: 9 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.: 9 Column: m

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.: 10 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.: 10 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.1 Line No.: 11 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.: 11 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.: 11 Column: m

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.: 12 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.: 12 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.1 Line No.: 13 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.: 13 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.: 13 Column: m

Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 14 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.: 14 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.1 Line No.: 15 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.: 15 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.: 16 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.: 16 Column: m

2017 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 17 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.: 17 Column: g

White Swan/Toppenish Substations

Schedule Page: 328.1 Line No.: 17 Column: m

Distribution voltage service charge. Primary delivery service. Regulation and frequency response service. Reactive supply and voltage control service. Operating reserve - spinning reserve service. Operating Reserve - supplemental reserve service.

Schedule Page: 328.1 Line No.: 18 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.: 18 Column: g

White Swan/Toppenish Substations

Schedule Page: 328.1 Line No.: 18 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.1 Line No.: 19 Column: d

Network transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 827) terminating on September 30, 2028.

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 827) terminating on September 30, 2028.

Schedule Page: 328.1 Line No.: 20 Column: m

2017 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 21 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (3rd Revised Service Agreement 746) terminating on June 30, 2028.

Schedule Page: 328.1 Line No.: 21 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.1 Line No.: 22 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (3rd Revised Service Agreement 746) terminating on June 30, 2028.

Schedule Page: 328.1 Line No.: 22 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.1 Line No.: 23 Column: b

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

Schedule Page: 328.1 Line No.: 23 Column: c

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

Schedule Page: 328.1 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: 328.1 Line No.: 23 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (2nd Revised Service Agreement 747) terminating on June 30, 2028.

Schedule Page: 328.1 Line No.: 26 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.: 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

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (2nd Revised Service Agreement 747) terminating on June 30, 2028.

Schedule Page: 328.1 Line No.: 27 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.1 Line No.: 28 Column: c

This footnote applies to all occurrences of “PUD No. 1 of Clark County” on pages 328-330. Complete name is Public Utility District No. 1 of Clark County.

Schedule Page: 328.1 Line No.: 28 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.: 28 Column: g

Chelatchie/View 115kV

Schedule Page: 328.1 Line No.: 28 Column: m

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.: 29 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.: 29 Column: g

Chelatchie/View 115kV

Schedule Page: 328.1 Line No.: 29 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.1 Line No.: 30 Column: b

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

Schedule Page: 328.1 Line No.: 30 Column: c

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

Schedule Page: 328.1 Line No.: 30 Column: d

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

Schedule Page: 328.1 Line No.: 30 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 31 Column: b

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

Schedule Page: 328.1 Line No.: 31 Column: c

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

Schedule Page: 328.1 Line No.: 31 Column: d

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

Schedule Page: 328.1 Line No.: 31 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.1 Line No.: 32 Column: d

Transmission service under the Open Access Transmission Tariff (12th 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.: 32 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.: 33 Column: d

Transmission service under the Open Access Transmission Tariff (12th 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.: 33 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

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

2017 annual transmission services true-up refunds and/or surcharge.

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

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

Schedule Page: 328.2 Line No.: 1 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

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
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 4 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 881) terminating on February 28, 2023.

Schedule Page: 328.2 Line No.: 4 Column: m
Scheduling, system control and dispatch service.

Schedule Page: 328.2 Line No.: 5 Column: b
This footnote applies to all occurrences of “Clatskanie People's Utility Distr” on pages 328-330. Complete name is Clatskanie People's Utility District.

Schedule Page: 328.2 Line No.: 5 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 899) terminating on December 31, 2020.

Schedule Page: 328.2 Line No.: 5 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 6 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 899) terminating on December 31, 2020.

Schedule Page: 328.2 Line No.: 6 Column: m
2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.2 Line No.: 7 Column: a
This footnote applies to all occurrences of "Deseret Generation and Transmission" on pages 328-330. Complete name is Deseret Generation and Transmission Co-operative.

Schedule Page: 328.2 Line No.: 7 Column: b
This footnote applies to all occurrences of "Deseret Gen and Trans" on pages 328-330. Complete name is Deseret Generation and Transmission Co-operative.

Schedule Page: 328.2 Line No.: 7 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: 328.2 Line No.: 7 Column: m
Distribution voltage service charge. Meter interrogation services. 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.: 8 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: 328.2 Line No.: 8 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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

2017 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 11 Column: b

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

Schedule Page: 328.2 Line No.: 11 Column: c

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

Schedule Page: 328.2 Line No.: 11 Column: d

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

Schedule Page: 328.2 Line No.: 11 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.2 Line No.: 12 Column: b

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

Schedule Page: 328.2 Line No.: 12 Column: c

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

Schedule Page: 328.2 Line No.: 12 Column: d

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

Schedule Page: 328.2 Line No.: 12 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 13 Column: c

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

Schedule Page: 328.2 Line No.: 13 Column: d

Transmission resale service under the Open Access Transmission Tariff (Service Agreement 780). Termination upon mutual consent.

Schedule Page: 328.2 Line No.: 13 Column: m

Transmission resale - purchase of point-to-point transmission. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.2 Line No.: 14 Column: c

This footnote applies to all occurrences of "PUD No. 2 of Grant County" on pages 328-330. Complete name is Public Utility District No. 2 of Grant County.

Schedule Page: 328.2 Line No.: 14 Column: d

Transmission resale service under the Open Access Transmission Tariff (Service Agreement 780). Termination upon mutual consent.

Schedule Page: 328.2 Line No.: 14 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.2 Line No.: 15 Column: b

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

Schedule Page: 328.2 Line No.: 15 Column: c

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

Schedule Page: 328.2 Line No.: 15 Column: d

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

Schedule Page: 328.2 Line No.: 15 Column: m

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.: 16 Column: c

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

Schedule Page: 328.2 Line No.: 16 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 711) which terminated on November 30, 2018.

Schedule Page: 328.2 Line No.: 16 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.2 Line No.: 17 Column: c

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

Schedule Page: 328.2 Line No.: 17 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 874) terminating on December 31, 2032.

Schedule Page: 328.2 Line No.: 17 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.: 18 Column: d

Transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 847). 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: 328.2 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: 328.2 Line No.: 19 Column: d

Transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 847). 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: 328.2 Line No.: 19 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge. Refunds for transmission services pursuant to FERC Docket No.

ER17-219-002.

Schedule Page: 328.2 Line No.: 20 Column: b

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

Schedule Page: 328.2 Line No.: 20 Column: c

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

Schedule Page: 328.2 Line No.: 20 Column: d

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

Schedule Page: 328.2 Line No.: 20 Column: m

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. Unauthorized use of transmission service.

Schedule Page: 328.2 Line No.: 21 Column: b

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

Schedule Page: 328.2 Line No.: 21 Column: c

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

Schedule Page: 328.2 Line No.: 21 Column: d

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

Schedule Page: 328.2 Line No.: 21 Column: m

2017 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

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.: 23 Column: a

This footnote applies to all occurrences of "Fall River Rural Electric Cooperative" on pages 328-330. Complete name is Fall River Rural Electric Cooperative, Inc.

Schedule Page: 328.2 Line No.: 23 Column: d

Legacy contract (Rate Schedule 322) executed between PacifiCorp and Fall River Rural Electric Cooperative for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Terminating on July 31, 2027.

Schedule Page: 328.2 Line No.: 23 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract.

Schedule Page: 328.2 Line No.: 24 Column: d

Legacy contract (Rate Schedule 322) executed between PacifiCorp and Fall River Rural Electric Cooperative for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Terminating on July 31, 2027.

Schedule Page: 328.2 Line No.: 24 Column: m

2017 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 25 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.: 25 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Distribution voltage service charge.

Schedule Page: 328.2 Line No.: 26 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.: 26 Column: m

2017 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 27 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.: 27 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 28 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.: 28 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.2 Line No.: 29 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 29 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

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.

Schedule Page: 328.2 Line No.: 30 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 30 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

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

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.2 Line No.: 31 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 31 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

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

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

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

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.2 Line No.: 33 Column: b

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

Schedule Page: 328.2 Line No.: 33 Column: c

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

Schedule Page: 328.2 Line No.: 33 Column: d

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

Schedule Page: 328.2 Line No.: 33 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 34 Column: b

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

Schedule Page: 328.2 Line No.: 34 Column: c

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

Schedule Page: 328.2 Line No.: 34 Column: d

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.: 34 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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

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

Schedule Page: 328.3 Line No.: 1 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 2 Column: b

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

Schedule Page: 328.3 Line No.: 2 Column: c

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

Schedule Page: 328.3 Line No.: 2 Column: d

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

Schedule Page: 328.3 Line No.: 2 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 3 Column: b

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

Schedule Page: 328.3 Line No.: 3 Column: c

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

Schedule Page: 328.3 Line No.: 3 Column: d

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

Schedule Page: 328.3 Line No.: 3 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 4 Column: 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: 328.3 Line No.: 4 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.: 5 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: 328.3 Line No.: 5 Column: m

2017 transmission and ancillary services.

Schedule Page: 328.3 Line No.: 6 Column: b

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

Schedule Page: 328.3 Line No.: 6 Column: c

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

Schedule Page: 328.3 Line No.: 6 Column: d

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

Schedule Page: 328.3 Line No.: 6 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 7 Column: b

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

Schedule Page: 328.3 Line No.: 7 Column: c

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

Schedule Page: 328.3 Line No.: 7 Column: d

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

Schedule Page: 328.3 Line No.: 7 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.3 Line No.: 8 Column: b

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

Schedule Page: 328.3 Line No.: 8 Column: c

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

Schedule Page: 328.3 Line No.: 8 Column: d

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

Schedule Page: 328.3 Line No.: 8 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 9 Column: b

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

Schedule Page: 328.3 Line No.: 9 Column: c

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

Schedule Page: 328.3 Line No.: 9 Column: d

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

Schedule Page: 328.3 Line No.: 9 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 10 Column: b

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

Schedule Page: 328.3 Line No.: 10 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 10 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 10 Column: m
2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.3 Line No.: 11 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 11 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 11 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 11 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 12 Column: d
Network transmission service under the Open Access Transmission Tariff (Service Agreement 894) terminating on December 31, 2057.

Schedule Page: 328.3 Line No.: 12 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: 328.3 Line No.: 13 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 13 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 13 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 14 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 14 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 14 Column: m
2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.3 Line No.: 15 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 15 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 15 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 15 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 16 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 733) terminating on November 30, 2023.

Schedule Page: 328.3 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: 328.3 Line No.: 17 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 733) terminating on November 30, 2023.

Schedule Page: 328.3 Line No.: 17 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.3 Line No.: 18 Column: b

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

Schedule Page: 328.3 Line No.: 18 Column: c

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

Schedule Page: 328.3 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: 328.3 Line No.: 18 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 19 Column: b

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

Schedule Page: 328.3 Line No.: 19 Column: c

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

Schedule Page: 328.3 Line No.: 19 Column: d

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

Schedule Page: 328.3 Line No.: 19 Column: m

2017 transmission and ancillary services.

Schedule Page: 328.3 Line No.: 20 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 20 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 20 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. Terminated on December 31, 2017. For further information refer to FERC Docket No. ER07-882-000, et al, Settlement Agreement, Appendix 2 (filed November 21, 2007).

Schedule Page: 328.3 Line No.: 20 Column: f

Malin to Indian Springs line segment

Schedule Page: 328.3 Line No.: 20 Column: g

Malin to Indian Springs line segment

Schedule Page: 328.3 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: 328.3 Line No.: 21 Column: b

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

Schedule Page: 328.3 Line No.: 21 Column: c

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

Schedule Page: 328.3 Line No.: 21 Column: d

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

Schedule Page: 328.3 Line No.: 21 Column: m

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

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

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.3 Line No.: 23 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 23 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 23 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 in December 2013.

Schedule Page: 328.3 Line No.: 23 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.: 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

2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.3 Line No.: 25 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.: 25 Column: d

Agreement providing for transmission service from Western Area Power Administration's Casper Substation in Wyoming and Yellowtail Substation in Montana to Sheridan-Johnson Rural Electric Association's load at PacifiCorp's Buffalo Substation in Wyoming.

Schedule Page: 328.3 Line No.: 25 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.: 26 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.: 26 Column: m

2017 transmission and ancillary services.

Schedule Page: 328.3 Line No.: 27 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.: 27 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.: 27 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 28 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.: 28 Column: m
2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.3 Line No.: 29 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 700) terminating on March 31, 2022.

Schedule Page: 328.3 Line No.: 29 Column: m
Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 30 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 700) terminating on March 31, 2022.

Schedule Page: 328.3 Line No.: 30 Column: m
2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.3 Line No.: 31 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 701) terminating on March 31, 2022.

Schedule Page: 328.3 Line No.: 31 Column: m
Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 32 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 701) terminating on March 31, 2022.

Schedule Page: 328.3 Line No.: 32 Column: m
2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.3 Line No.: 33 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 702) terminating on March 31, 2022.

Schedule Page: 328.3 Line No.: 33 Column: m
Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 34 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 702) terminating on March 31, 2022.

Schedule Page: 328.3 Line No.: 34 Column: m
2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.4 Line No.: 1 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (1st Revised Service Agreement 748) which terminated on December 31, 2018.

Schedule Page: 328.4 Line No.: 1 Column: m
Scheduling, system control and dispatch service.

Schedule Page: 328.4 Line No.: 2 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (1st Revised Service Agreement 748) which terminated on December 31, 2018.

Schedule Page: 328.4 Line No.: 2 Column: m
2017 transmission and ancillary services. 2017 annual transmission services true-up

refunds and/or surcharge.

Schedule Page: 328.4 Line No.: 3 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (1st Revised Service Agreement 749) which terminated on December 31, 2018.

Schedule Page: 328.4 Line No.: 3 Column: m

Scheduling, system control and dispatch service.

Schedule Page: 328.4 Line No.: 4 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (1st Revised Service Agreement 749) which terminated on December 31, 2018.

Schedule Page: 328.4 Line No.: 4 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.4 Line No.: 5 Column: b

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

Schedule Page: 328.4 Line No.: 5 Column: c

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

Schedule Page: 328.4 Line No.: 5 Column: d

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

Schedule Page: 328.4 Line No.: 5 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 6 Column: b

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

Schedule Page: 328.4 Line No.: 6 Column: c

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

Schedule Page: 328.4 Line No.: 6 Column: d

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

Schedule Page: 328.4 Line No.: 6 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.4 Line No.: 7 Column: b

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

Schedule Page: 328.4 Line No.: 7 Column: c

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

Schedule Page: 328.4 Line No.: 7 Column: d

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

Schedule Page: 328.4 Line No.: 7 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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

2017 annual transmission services true-up refunds and/or surcharge.

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

2017 annual transmission services true-up refunds and/or surcharge.

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

2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.4 Line No.: 11 Column: a

This footnote applies to all occurrences of "PUD No. 1 of Cowlitz County" on pages 328-330. Complete name is Public Utility District No. 1 of Cowlitz County.

Schedule Page: 328.4 Line No.: 11 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: 328.4 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: 328.4 Line No.: 12 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: 328.4 Line No.: 12 Column: m

2017 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.

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

This footnote applies to all occurrences of "Sacramento Municipal Utility Dist" on pages 328-330. Complete name is Sacramento Municipal Utility District.

Schedule Page: 328.4 Line No.: 15 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 863) terminating on June 30, 2022.

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: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 863) terminating on June 30, 2022.

Schedule Page: 328.4 Line No.: 16 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.4 Line No.: 17 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 809) terminating on October 31, 2020.

Schedule Page: 328.4 Line No.: 17 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 18 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 809) terminating on October 31, 2020.

Schedule Page: 328.4 Line No.: 18 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.4 Line No.: 19 Column: b

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

Schedule Page: 328.4 Line No.: 19 Column: c

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

Schedule Page: 328.4 Line No.: 19 Column: d

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

Schedule Page: 328.4 Line No.: 19 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 20 Column: b

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

Schedule Page: 328.4 Line No.: 20 Column: c

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

Schedule Page: 328.4 Line No.: 20 Column: d

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

Schedule Page: 328.4 Line No.: 20 Column: m

2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.4 Line No.: 21 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (9th Revised Service Agreement 289) which terminated on October 11, 2014.

Schedule Page: 328.4 Line No.: 21 Column: m

2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.4 Line No.: 22 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (9th Revised

Service Agreement 791) terminating upon written notification.

Schedule Page: 328.4 Line No.: 23 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (9th Revised Service Agreement 791) terminating upon written notification.

Schedule Page: 328.4 Line No.: 24 Column: b

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

Schedule Page: 328.4 Line No.: 24 Column: c

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

Schedule Page: 328.4 Line No.: 24 Column: d

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

Schedule Page: 328.4 Line No.: 24 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 25 Column: b

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

Schedule Page: 328.4 Line No.: 25 Column: c

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

Schedule Page: 328.4 Line No.: 25 Column: d

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

Schedule Page: 328.4 Line No.: 25 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.4 Line No.: 26 Column: b

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

Schedule Page: 328.4 Line No.: 26 Column: c

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

Schedule Page: 328.4 Line No.: 26 Column: d

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

Schedule Page: 328.4 Line No.: 26 Column: m

Transmission resale - purchase of point-to-point transmission. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.4 Line No.: 27 Column: b

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

Schedule Page: 328.4 Line No.: 27 Column: c

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

Schedule Page: 328.4 Line No.: 27 Column: d

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

Schedule Page: 328.4 Line No.: 27 Column: m

2017 transmission and ancillary services.

Schedule Page: 328.4 Line No.: 28 Column: a

This footnote applies to all occurrences of "Sierra Pacific Power Company" on pages 328-330. 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.: 28 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 28 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 28 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.: 28 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.: 29 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 29 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 29 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.: 29 Column: m

2017 transmission and ancillary services.

Schedule Page: 328.4 Line No.: 30 Column: b

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

Schedule Page: 328.4 Line No.: 30 Column: c

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

Schedule Page: 328.4 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: 328.4 Line No.: 30 Column: m

2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.4 Line No.: 31 Column: d

Ancillary services under the Open Access Transmission Tariff.

Schedule Page: 328.4 Line No.: 31 Column: m

Generation regulation and frequency response service.

Schedule Page: 328.4 Line No.: 32 Column: d

Ancillary services under the Open Access Transmission Tariff.

Schedule Page: 328.4 Line No.: 32 Column: m

Generation regulation and frequency response service.

Schedule Page: 328.4 Line No.: 33 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 33 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 33 Column: d

Use of facilities agreement (Rate Schedule 298) for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge (phase shifting transformers at Sigurd-Glen Canyon 230kV transmission line and Pinto-Four Corners 345kV transmission line), terminating February 12, 2020.

Schedule Page: 328.4 Line No.: 33 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.: 34 Column: b

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

Schedule Page: 328.4 Line No.: 34 Column: c

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

Schedule Page: 328.4 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: 328.4 Line No.: 34 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: 328.5 Line No.: 1 Column: b

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

Schedule Page: 328.5 Line No.: 1 Column: c

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

Schedule Page: 328.5 Line No.: 1 Column: d

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

Schedule Page: 328.5 Line No.: 1 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.5 Line No.: 2 Column: c

This footnote applies to all occurrences of "Southern California Public Power" on pages 328-330. Complete name is Southern California Public Power Authority.

Schedule Page: 328.5 Line No.: 2 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: 328.5 Line No.: 2 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: 328.5 Line No.: 3 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: 328.5 Line No.: 3 Column: m

Unauthorized use of transmission service.

Schedule Page: 328.5 Line No.: 4 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 779) terminating on August 31, 2019.

Schedule Page: 328.5 Line No.: 4 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 5 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 779) terminating on August 31, 2019.

Schedule Page: 328.5 Line No.: 5 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.5 Line No.: 6 Column: b

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

Schedule Page: 328.5 Line No.: 6 Column: c

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

Schedule Page: 328.5 Line No.: 6 Column: d

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

Schedule Page: 328.5 Line No.: 6 Column: m

2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.5 Line No.: 7 Column: b

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

Schedule Page: 328.5 Line No.: 7 Column: c

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

Schedule Page: 328.5 Line No.: 7 Column: d

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

Schedule Page: 328.5 Line No.: 7 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 8 Column: b

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

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

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.: 8 Column: m

2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.5 Line No.: 9 Column: b

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

Schedule Page: 328.5 Line No.: 9 Column: c

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

Schedule Page: 328.5 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: 328.5 Line No.: 9 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 10 Column: b

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

Schedule Page: 328.5 Line No.: 10 Column: c

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

Schedule Page: 328.5 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: 328.5 Line No.: 10 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 11 Column: b

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

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

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

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

Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 568) terminating on April 30, 2029.

Schedule Page: 328.5 Line No.: 12 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control

service. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve 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

Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 568) terminating on April 30, 2029.

Schedule Page: 328.5 Line No.: 13 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.5 Line No.: 14 Column: b

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

Schedule Page: 328.5 Line No.: 14 Column: c

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

Schedule Page: 328.5 Line No.: 14 Column: d

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

Schedule Page: 328.5 Line No.: 14 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 15 Column: b

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

Schedule Page: 328.5 Line No.: 15 Column: c

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

Schedule Page: 328.5 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: 328.5 Line No.: 15 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.5 Line No.: 16 Column: b

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

Schedule Page: 328.5 Line No.: 16 Column: c

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

Schedule Page: 328.5 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: 328.5 Line No.: 16 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 17 Column: a

This footnote applies to all occurrences of "Tri-State Generation and Transmission" on pages 328-330. Complete name is Tri-State Generation and Transmission Association, Inc.

Schedule Page: 328.5 Line No.: 17 Column: b

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

Schedule Page: 328.5 Line No.: 17 Column: c

This footnote applies to all occurrences of "Tri-State Gen and Trans" on pages 328-330. Complete name is Tri-State Generation and Transmission Association, Inc.

Schedule Page: 328.5 Line No.: 17 Column: d

Network transmission service under the Open Access Transmission Tariff (7th Revised Service Agreement 628) terminating on June 30, 2021.

Schedule Page: 328.5 Line No.: 17 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.5 Line No.: 18 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 18 Column: d
Network transmission service under the Open Access Transmission Tariff (7th Revised Service Agreement 628) terminating on June 30, 2021.

Schedule Page: 328.5 Line No.: 18 Column: m
2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.5 Line No.: 19 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 19 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 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: 328.5 Line No.: 19 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 20 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 20 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 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: 328.5 Line No.: 20 Column: m
2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.5 Line No.: 21 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 21 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 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: 328.5 Line No.: 21 Column: m
2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.5 Line No.: 22 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: 328.5 Line No.: 22 Column: m
Distribution voltage service charge. Primary delivery service. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.5 Line No.: 23 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: 328.5 Line No.: 23 Column: m
2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.5 Line No.: 24 Column: c
This footnote applies to all occurrences of "Weber Basin Water Conserv." on pages 328-330. Complete name is Weber Basin Water Conservancy District.

Schedule Page: 328.5 Line No.: 24 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 terminates any time after April 1, 2040, with four years written notification.

Schedule Page: 328.5 Line No.: 24 Column: m

Energy consumption charge for deliveries at and below 138kV.

Schedule Page: 328.5 Line No.: 25 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 terminates any time after April 1, 2040, with four years written notification.

Schedule Page: 328.5 Line No.: 25 Column: m

2017 transmission and ancillary services.

Schedule Page: 328.5 Line No.: 26 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 terminates with one year written notice.

Schedule Page: 328.5 Line No.: 27 Column: b

This footnote applies to all occurrences of "Utah Associated Municipal Power" on pages 328-330. Complete name is Utah Associated Municipal Power Systems.

Schedule Page: 328.5 Line No.: 27 Column: d

Legacy contract executed between PacifiCorp and Utah Associated Municipal Power Systems for transmission service over agreed-upon facilities (4th 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: 328.5 Line No.: 27 Column: m

Distribution voltage service charge. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.5 Line No.: 28 Column: d

Legacy contract executed between PacifiCorp and Utah Associated Municipal Power Systems for transmission service over agreed-upon facilities (4th 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: 328.5 Line No.: 28 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.5 Line No.: 29 Column: b

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

Schedule Page: 328.5 Line No.: 29 Column: c

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

Schedule Page: 328.5 Line No.: 29 Column: d

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

Schedule Page: 328.5 Line No.: 29 Column: m

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

Schedule Page: 328.5 Line No.: 30 Column: b

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

Schedule Page: 328.5 Line No.: 30 Column: c

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

Schedule Page: 328.5 Line No.: 30 Column: d

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

Schedule Page: 328.5 Line No.: 30 Column: m

2017 transmission and ancillary services.

Schedule Page: 328.5 Line No.: 31 Column: b

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

Schedule Page: 328.5 Line No.: 31 Column: c

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

Schedule Page: 328.5 Line No.: 31 Column: d

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

Schedule Page: 328.5 Line No.: 31 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 32 Column: d

Legacy contract (5th Revised Rate Schedule 637) executed between PacifiCorp and Utah Municipal Power Agency for transmission service over agreed-upon facilities (Amended and Restated Transmission Service and Operating Agreement). Subject to termination upon mutual agreement and replacement agreements are in effect.

Schedule Page: 328.5 Line No.: 32 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.5 Line No.: 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: 328.5 Line No.: 33 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.5 Line No.: 34 Column: c

This footnote applies to all occurrences of "PGE" on pages 328-330. Complete name is Portland General Electric Company.

Schedule Page: 328.5 Line No.: 34 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.: 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: 328.6 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: 328.6 Line No.: 1 Column: m

2017 transmission and ancillary services.

Schedule Page: 328.6 Line No.: 2 Column: b

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

Schedule Page: 328.6 Line No.: 2 Column: c

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

Schedule Page: 328.6 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: 328.6 Line No.: 2 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.6 Line No.: 3 Column: c

Various Western Area Power Administration customers in PacifiCorp's control area.

Schedule Page: 328.6 Line No.: 3 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 terminates upon three years after written notice and mutual consent.

Schedule Page: 328.6 Line No.: 3 Column: m

Fixed termination fee associated with a contract cancellation applied for the duration of this agreement.

Schedule Page: 328.6 Line No.: 4 Column: c

Various Western Area Power Administration customers in PacifiCorp's control area.

Schedule Page: 328.6 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 terminates upon three years after written notice and mutual consent.

Schedule Page: 328.6 Line No.: 4 Column: m

2017 transmission and ancillary services.

Schedule Page: 328.6 Line No.: 5 Column: c

Various Western Area Power Administration customers in PacifiCorp's control area.

Schedule Page: 328.6 Line No.: 5 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: 328.6 Line No.: 5 Column: m

Charges for low-voltage transmission of power and energy.

Schedule Page: 328.6 Line No.: 6 Column: c

Various Western Area Power Administration customers in PacifiCorp's control area.

Schedule Page: 328.6 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: 328.6 Line No.: 6 Column: m

2017 transmission and ancillary services.

Schedule Page: 328.6 Line No.: 7 Column: c

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

Schedule Page: 328.6 Line No.: 7 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: 328.6 Line No.: 8 Column: d

Evergreen network transmission service under the Open Access Transmission Tariff (4th Revised Service Agreement 175).

Schedule Page: 328.6 Line No.: 8 Column: m

Distribution voltage service charge. Primary delivery service. Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.6 Line No.: 9 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: 328.6 Line No.: 9 Column: d

Evergreen network transmission service under the Open Access Transmission Tariff (4th Revised Service Agreement 175).

Schedule Page: 328.6 Line No.: 9 Column: m

2017 transmission and ancillary services. 2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.6 Line No.: 10 Column: c

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

Schedule Page: 328.6 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: 328.6 Line No.: 10 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.6 Line No.: 11 Column: c

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

Schedule Page: 328.6 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: 328.6 Line No.: 11 Column: m

2017 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.6 Line No.: 12 Column: a

Complete name is Western Area Power Administration Colorado Missouri.

Schedule Page: 328.6 Line No.: 12 Column: c

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

Schedule Page: 328.6 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: 328.6 Line No.: 12 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.6 Line No.: 13 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 2018/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	Adams Solar Center LLC	LFP			-33,682			-33,682
2	Adams Solar Center LLC	OS					-8,950	-8,950
3	Adams Solar Center LLC	AD					-31,897	-31,897
4	Arizona Public Service	AD					17,667	17,667
5	Arizona Public Service	LFP	225,569	225,569	1,069,941			1,069,941
6	Arizona Public Service	NF	32,872	32,872	227,082			227,082
7	Arizona Public Service	OS	1,638	1,639			700,703	700,703
8	Arizona Public Service	SFP	68,003	68,003	850,309			850,309
9	Ashland, City of	FNS	13,090	13,090		23,476		23,476
10	Avista Corporation	FNS	274	848	219,077			219,077
11	Avista Corporation	NF	3,846	3,846	36,534			36,534
12	Avista Corporation	SFP	21,726	21,726	1,110,295			1,110,295
13	Basin Elect. Power Coop	NF	158,518	158,518	1,725			1,725
14	Big Horn Rural Electric	OLF					164,875	164,875
15	Big Horn Rural Electric	AD					1,116	1,116
16	Black Hills Power, Inc.	SFP	33,574	33,574	194,534			194,534
	TOTAL		21,138,401	21,354,478	120,661,469	247,558	14,112,570	135,021,597

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 2018/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	Black Hills Power, Inc.	NF	16,668	16,668	16,668			16,668
2	Black Hills Power, Inc.	OS					51,044	51,044
3	Bonneville Power Admin	AD					75,242	75,242
4	Bonneville Power Admin	FNS	2,802	2,853	5,625,581			5,625,581
5	Bonneville Power Admin	LFP	5,115,731	5,209,591	52,940,308			52,940,308
6	Bonneville Power Admin	NF	35,936	36,595	128,881			128,881
7	Bonneville Power Admin	OLF	5,580,565	5,682,953	19,919,767			19,919,767
8	Bonneville Power Admin	OS					17,156,699	17,156,699
9	Bonneville Power Admin	SFP	270,270	275,229	1,270,795			1,270,795
10	CA Ind Sys Operator	AD	35,593	35,593			-329,909	-329,909
11	CA Ind Sys Operator	OS					2,169,654	2,169,654
12	CA Ind Sys Operator	SFP				222,576		222,576
13	Deseret Gen and Trans	OS					1,676,000	1,676,000
14	Deseret Gen and Trans	LFP	616,684	616,684	3,919,090			3,919,090
15	Deseret Gen and Trans	NF	281,424	281,424	55,903			55,903
16	Elbe Solar Center, LLC	LFP			-168,771			-168,771
	TOTAL		21,138,401	21,354,478	120,661,469	247,558	14,112,570	135,021,597

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 2018/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	Elbe Solar Center, LLC	OS					-44,749	-44,749
2	Elbe Solar Center, LLC	AD					-159,484	-159,484
3	El Paso Electric Co.	SFP	27,160	27,160	17,690			17,690
4	EOG Resources, Inc.	OS					-1,676,000	-1,676,000
5	Flathead Elect Coop Inc	OS					98,108	98,108
6	Flathead Elect Coop Inc	AD					4,368	4,368
7	Hermiston Gen Co L.P.	OS					201,050	201,050
8	Idaho Power Company	FNS			11,941			11,941
9	Idaho Power Company	LFP	3,341,010	3,349,612	17,333,523			17,333,523
10	Idaho Power Company	NF	1,064,144	1,064,144	235,458			235,458
11	Idaho Power Company	SFP	9,964	9,964	1,194,791			1,194,791
12	Idaho Power Company	OS	231,061	231,061			-3,347,325	-3,347,325
13	LA Dept. of Water & Pwr	NF	1	1	4			4
14	LA Dept. of Water & Pwr	SFP	50	50	424			424
15	LA Dept. of Water & Pwr	OS					43	43
16	Moon Lake Elect. Assoc.	FNS	16	16			275,777	275,777
	TOTAL		21,138,401	21,354,478	120,661,469	247,558	14,112,570	135,021,597

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 2018/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	Morgan City Corporation	AD					1,446	1,446
2	Morgan City Corporation	LFP				1,506		1,506
3	Nevada Power Company	AD					-5,135	-5,135
4	Nevada Power Company	NF	15,463	15,463	267,204			267,204
5	Nevada Power Company	OS	46,481	46,481			178,452	178,452
6	Nevada Power Company	SFP	260,640	260,640	1,236,250			1,236,250
7	NorthWestern Corp.	NF	18,346	18,803	62,551			62,551
8	NorthWestern Corp.	SFP	4,053	4,137	6,442			6,442
9	NorthWestern Corp.	OS					3,620	3,620
10	Platte River Pwr Auth	LFP	163,775	163,775	849,350			849,350
11	Platte River Pwr Auth	NF	55,227	55,227	10			10
12	Platte River Pwr Auth	SFP			25,481			25,481
13	Platte River Pwr Auth	OS					20,619	20,619
14	Portland Gen. Electric	LFP	103,954	103,954	75,360			75,360
15	Portland Gen. Electric	OLF					1,001	1,001
16	Portland Gen. Electric	OS		4,442			7,331	7,331
	TOTAL		21,138,401	21,354,478	120,661,469	247,558	14,112,570	135,021,597

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 2018/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	Powerex Corporation	SFP					-63,850	-63,850
2	Public Service Co of CO	LFP	219,600	219,600	1,079,311			1,079,311
3	Public Service Co of CO	NF	110,558	110,558	864			864
4	Public Service Co of CO	OS					70	70
5	Puget Sound Energy, Inc	SFP	14,400	14,400	29,600			29,600
6	Salt River Project	NF	1,550	1,550	2,865			2,865
7	Salt River Project	OS					337	337
8	Sierra Pacific Power Co	SFP	93,000	93,000	331,250			331,250
9	Sierra Pacific Power Co	NF	1,530	1,530	9,088			9,088
10	Sierra Pacific Power Co	OS					26,738	26,738
11	Surprise Valley Electr.	AD					608	608
12	Surprise Valley Electr.	OLF					7,302	7,302
13	The Energy Authority	SFP					-127,704	-127,704
14	TransAlta Energy	SFP					-63,132	-63,132
15	Tri-State Gen and Trans	LFP	219,600	219,600	1,084,031			1,084,031
16	Tri-State Gen and Trans	NF	114,792	114,792	27,893			27,893
	TOTAL		21,138,401	21,354,478	120,661,469	247,558	14,112,570	135,021,597

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 2018/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 and Trans	SFP	1,068	1,068	3,608			3,608
2	Tri-State Gen and Trans	OS					4,064	4,064
3	Tucson Electric Pwr Co.	NF	100	100	8,639			8,639
4	Tucson Electric Pwr Co.	SFP	6,059	6,059	4,939			4,939
5	Tucson Electric Pwr Co.	OS					1,212	1,212
6	Western Area Power Admn	FNS	684,692	684,692	5,957,391			5,957,391
7	Western Area Power Admn	LFP	963,384	963,384	2,260,417			2,260,417
8	Western Area Power Admn	NF	698,004	698,004	852,507			852,507
9	Western Area Power Admn	OS	79,859	79,859			804,276	804,276
10	Western Area Power Admn	AD					-25,296	-25,296
11	Western Area Power Admn	SFP	74,077	74,077	308,550			308,550
12	Westport Field Srv Llc	LFP					-3,147,109	-3,147,109
13	Accrual						-506,312	-506,312
14								
15								
16								
	TOTAL		21,138,401	21,354,478	120,661,469	247,558	14,112,570	135,021,597

Schedule Page: 332 Line No.: 1 Column: b
Adams Solar Center LLC - contract termination date: October 30, 2036.

Schedule Page: 332 Line No.: 2 Column: b
Ancillary services.

Schedule Page: 332 Line No.: 2 Column: g
Ancillary services.

Schedule Page: 332 Line No.: 3 Column: b
Settlement adjustment.

Schedule Page: 332 Line No.: 3 Column: g
Settlement adjustment.

Schedule Page: 332 Line No.: 4 Column: b
Settlement adjustment.

Schedule Page: 332 Line No.: 4 Column: g
Settlement adjustment.

Schedule Page: 332 Line No.: 5 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.: 7 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 328-330, Transmission of electricity for others, in this Form No. 1.

Schedule Page: 332 Line No.: 7 Column: g
Ancillary services.

Schedule Page: 332 Line No.: 13 Column: a
Complete name is Basin Electric Power Cooperative, Inc.

Schedule Page: 332 Line No.: 14 Column: b
Big Horn Rural Electric Company - contract termination date: March 10, 2021.

Schedule Page: 332 Line No.: 14 Column: g
Use of facilities.

Schedule Page: 332 Line No.: 15 Column: b
Settlement adjustment.

Schedule Page: 332 Line No.: 15 Column: g
Settlement adjustment.

Schedule Page: 332.1 Line No.: 2 Column: b
Ancillary services.

Schedule Page: 332.1 Line No.: 2 Column: g
Ancillary services.

Schedule Page: 332.1 Line No.: 3 Column: b
Settlement adjustment.

Schedule Page: 332.1 Line No.: 3 Column: g
Settlement adjustment.

Schedule Page: 332.1 Line No.: 5 Column: b
Bonneville Power Administration - contract termination dates: April 1, 2018; July 1, 2018; October 1, 2018; December 1, 2018; January 1, 2019; July 1, 2019; September 1, 2019; October 1, 2019; November 1, 2019; November 1, 2020; January 1, 2021; July 1, 2021; November 1, 2021; December 1, 2021; January 1, 2022; March 1, 2022; April 1, 2022; July 1, 2022; November 1, 2022; March 1, 2023; July 1, 2023; December 1, 2023; November 1, 2027; November 1, 2033 and evergreen.

Schedule Page: 332.1 Line No.: 7 Column: b
Bonneville Power Administration - contract termination dates: December 31, 2018; September 30, 2027 and evergreen.

Schedule Page: 332.1 Line No.: 8 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 328-330, Transmission of electricity for others, in this Form No. 1.

Schedule Page: 332.1 Line No.: 8 Column: g

Ancillary services. Use of facilities.

Schedule Page: 332.1 Line No.: 10 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.: 10 Column: b

Settlement adjustment.

Schedule Page: 332.1 Line No.: 10 Column: g

Settlement adjustment.

Schedule Page: 332.1 Line No.: 11 Column: b

Ancillary services.

Schedule Page: 332.1 Line No.: 11 Column: g

Ancillary services.

Schedule Page: 332.1 Line No.: 13 Column: a

This footnote applies to all occurrences of "Deseret Gen and Trans" on page 332. The complete name is Deseret Generation and Transmission Co-operative.

Schedule Page: 332.1 Line No.: 13 Column: b

Termination and settlement of firm point-to-point transmission request.

Schedule Page: 332.1 Line No.: 13 Column: g

Termination and settlement of firm point-to-point transmission request.

Schedule Page: 332.1 Line No.: 14 Column: b

Deseret Generation and Transmission Co-operative - contract termination date: November 1, 2022.

Schedule Page: 332.1 Line No.: 16 Column: b

Elbe Solar Center, LLC - contract termination date: October 30, 2036.

Schedule Page: 332.2 Line No.: 1 Column: b

Ancillary services.

Schedule Page: 332.2 Line No.: 1 Column: g

Ancillary services.

Schedule Page: 332.2 Line No.: 2 Column: b

Settlement adjustment.

Schedule Page: 332.2 Line No.: 2 Column: g

Settlement adjustment.

Schedule Page: 332.2 Line No.: 3 Column: a

Complete name is El Paso Electric Company.

Schedule Page: 332.2 Line No.: 4 Column: b

Termination and settlement of firm point-to-point transmission request.

Schedule Page: 332.2 Line No.: 4 Column: g

Termination and settlement of firm point-to-point transmission request.

Schedule Page: 332.2 Line No.: 5 Column: a

Complete name is Flathead Electric Cooperative, Inc.

Schedule Page: 332.2 Line No.: 5 Column: b

Use of facilities.

Schedule Page: 332.2 Line No.: 5 Column: g

Use of facilities.

Schedule Page: 332.2 Line No.: 6 Column: b

Settlement adjustment.

Schedule Page: 332.2 Line No.: 6 Column: g
Settlement adjustment.

Schedule Page: 332.2 Line No.: 7 Column: a
Complete name is Hermiston Generating Company, L.P.

Schedule Page: 332.2 Line No.: 7 Column: b
Hermiston Generating Company, L.P. operates the Hermiston Generating Plant, which is jointly owned. PacifiCorp owns 50% of the plant.

Schedule Page: 332.2 Line No.: 7 Column: g
Use of facilities.

Schedule Page: 332.2 Line No.: 9 Column: b
Idaho Power Company - contract termination dates: April 1, 2025 and July 1, 2025.

Schedule Page: 332.2 Line No.: 12 Column: b
Ancillary services. Credit for unreserved use.

Schedule Page: 332.2 Line No.: 12 Column: g
Ancillary Services. Credit for unreserved use.

Schedule Page: 332.2 Line No.: 13 Column: a
This footnote applies to all occurrences of "LA Dept. of Water & Pwr" on page 332. Complete name is Los Angeles Department of Water and Power.

Schedule Page: 332.2 Line No.: 15 Column: b
Ancillary services.

Schedule Page: 332.2 Line No.: 15 Column: g
Ancillary services.

Schedule Page: 332.2 Line No.: 16 Column: a
Complete name is Moon Lake Electric Association Inc.

Schedule Page: 332.2 Line No.: 16 Column: g
Use of facilities.

Schedule Page: 332.3 Line No.: 1 Column: b
Settlement adjustment.

Schedule Page: 332.3 Line No.: 1 Column: g
Settlement adjustment.

Schedule Page: 332.3 Line No.: 2 Column: b
Morgan City Corporation - contract termination date: Evergreen.

Schedule Page: 332.3 Line No.: 3 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: 332.3 Line No.: 3 Column: b
Settlement adjustment.

Schedule Page: 332.3 Line No.: 3 Column: g
Settlement adjustment.

Schedule Page: 332.3 Line No.: 5 Column: b
Ancillary services.

Schedule Page: 332.3 Line No.: 5 Column: g
Ancillary services.

Schedule Page: 332.3 Line No.: 9 Column: b
Ancillary services.

Schedule Page: 332.3 Line No.: 9 Column: g
Ancillary services.

Schedule Page: 332.3 Line No.: 10 Column: a
This footnote applies to all occurrences of "Platte River Pwr Auth" on page 332. Complete name is Platte River Power Authority.

Schedule Page: 332.3 Line No.: 10 Column: b
Platte River Power Authority - contract termination date: October 31, 2022.

Schedule Page: 332.3 Line No.: 13 Column: b
Ancillary services.

Schedule Page: 332.3 Line No.: 13 Column: g
Ancillary services.

Schedule Page: 332.3 Line No.: 14 Column: a
This footnote applies to all occurrences of "Portland Gen. Electric" on page 332. Complete name is Portland General Electric Company.

Schedule Page: 332.3 Line No.: 14 Column: b
Portland General Electric Company - contract termination date: April 1, 2022.

Schedule Page: 332.3 Line No.: 15 Column: b
Portland General Electric Company - contract termination date: Upon two years written notice.

Schedule Page: 332.3 Line No.: 15 Column: g
Use of facilities.

Schedule Page: 332.3 Line No.: 16 Column: b
Ancillary services.

Schedule Page: 332.3 Line No.: 16 Column: g
Ancillary services.

Schedule Page: 332.4 Line No.: 1 Column: g
Revenues from sales on the secondary transmission market.

Schedule Page: 332.4 Line No.: 2 Column: a
This footnote applies to all occurrences of "Public Service Co of CO" on page 332. Complete name is Public Service Company of Colorado.

Schedule Page: 332.4 Line No.: 2 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: 332.4 Line No.: 4 Column: b
Ancillary services.

Schedule Page: 332.4 Line No.: 4 Column: g
Ancillary services.

Schedule Page: 332.4 Line No.: 7 Column: b
Ancillary services.

Schedule Page: 332.4 Line No.: 7 Column: g
Ancillary services.

Schedule Page: 332.4 Line No.: 8 Column: a
This footnote applies to all occurrences of "Sierra Pacific Power Co" on page 332. Sierra Pacific Power Company is a wholly owned subsidiary of NV Energy, Inc., which is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company, PacifiCorp's indirect parent company.

Schedule Page: 332.4 Line No.: 10 Column: b
Ancillary services.

Schedule Page: 332.4 Line No.: 10 Column: g
Ancillary services.

Schedule Page: 332.4 Line No.: 11 Column: a
This footnote applies to all occurrences of "Surprise Valley Electr." on page 332. Complete name is Surprise Valley Electrification Corp.

Schedule Page: 332.4 Line No.: 11 Column: b
Settlement adjustment.

Schedule Page: 332.4 Line No.: 11 Column: g
Settlement adjustment.

Schedule Page: 332.4 Line No.: 12 Column: b
Surprise Valley Electrification Corp. - contract termination date: Evergreen.

Schedule Page: 332.4 Line No.: 12 Column: g

Use of facilities.

Schedule Page: 332.4 Line No.: 13 Column: g

Revenues from sales on the secondary transmission market.

Schedule Page: 332.4 Line No.: 14 Column: a

Complete name is TransAlta Energy Marketing (U.S.) Inc.

Schedule Page: 332.4 Line No.: 14 Column: g

Revenues from sales on the secondary transmission market.

Schedule Page: 332.4 Line No.: 15 Column: a

This footnote applies to all occurrences of "Tri-State Gen and Trans" on page 332. The complete name is Tri-State Generation and Transmission Association, Inc.

Schedule Page: 332.4 Line No.: 15 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: 332.5 Line No.: 2 Column: b

Ancillary services.

Schedule Page: 332.5 Line No.: 2 Column: g

Ancillary services.

Schedule Page: 332.5 Line No.: 3 Column: a

This footnote applies to all occurrences of "Tucson Electric Pwr Co." on page 332. The complete name is Tucson Electric Power Company.

Schedule Page: 332.5 Line No.: 5 Column: b

Ancillary services.

Schedule Page: 332.5 Line No.: 5 Column: g

Ancillary services.

Schedule Page: 332.5 Line No.: 7 Column: b

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

Schedule Page: 332.5 Line No.: 9 Column: b

Western Area Power Administration - 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 328-330, Transmission of electricity for others, in this Form No. 1.

Schedule Page: 332.5 Line No.: 9 Column: g

Ancillary Services. Use of Facilities.

Schedule Page: 332.5 Line No.: 10 Column: b

Settlement adjustment.

Schedule Page: 332.5 Line No.: 10 Column: g

Settlement adjustment.

Schedule Page: 332.5 Line No.: 12 Column: b

Westport Field Services, LLC - contract termination date: Evergreen.

Schedule Page: 332.5 Line No.: 12 Column: g

Reimbursement for third party services.

Schedule Page: 332.5 Line No.: 13 Column: g

Represents the difference between actual wheeling expenses for the period as reflected on the individual line items within this schedule and the accruals charged to Account 565, 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 2018/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,338,912
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	Business & Economic Development and	
8	Corporate Memberships & Subscriptions:	
9	Alliance for Transportation Electrification	10,000
10	American Leadership Forum of Oregon	10,000
11	American Wind Wildlife Institute	25,000
12	Clatsop Economic Development Resources	6,000
13	Economic Development for Central Oregon	7,500
14	Greater Yakima Chamber of Commerce	5,000
15	Klamath County Economic Development Association	6,000
16	Laramie Chamber of Business Alliance	5,000
17	Ogden-Weber Chamber of Commerce	6,000
18	Oregon Business Council	33,777
19	Oregon Economic Development Association	13,500
20	Redmond Economic Development, Inc.	7,000
21	Salt Lake Chamber	28,000
22	Sandy Area Chamber of Commerce	5,000
23	South Coast Development Council, Inc.	5,000
24	Southern Oregon Regional Economic Development, Inc	5,700
25	Utah Clean Air Partnership UCAIR Inc.	5,000
26	Utah Manufacturers Association	5,544
27	Utah Taxpayers Association	18,700
28	Utah Technology Council	8,400
29	Walla Walla Valley Chamber of Commerce	15,000
30	Wyoming Business Alliance	5,000
31	Yakima County Development Association	7,980
32	Other (Individually < $5,000)	156,506
33		
34	Rating Agency and Trustee Fees:	
35	The Bank of New York Mellon	129,475
36	Computershare Shareowner Services, LLC	17,733
37	Moody's Investors Service, Inc.	112,990
38	Standard and Poor's Financial Services, LLC	205,259
39	U.S. Bank National Association	16,085
40	Other (Individually < $5,000)	2,468
41		
42	General:	
43	Other	2,160
44		
45		
46	TOTAL	2,225,689

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 2018/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			45,506,528		45,506,528
2	Steam Production Plant	439,095,633				439,095,633
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	36,103,407		309,776		36,413,183
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	127,480,652				127,480,652
7	Transmission Plant	109,403,638				109,403,638
8	Distribution Plant	154,815,630				154,815,630
9	Regional Transmission and Market Operation					
10	General Plant	41,562,941		1,067,414		42,630,355
11	Common Plant-Electric					
12	TOTAL	908,461,901		46,883,718		955,345,619

B. Basis for Amortization Charges

The Amortization of Limited-Term Electric Plant is based on straight-line amortization over the life of the asset.

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 2018/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	HYDRAULIC PROD.						
13	Klamath River						
14	330.20 CA/OR	41			-5.16		1.00
15	330.40 CA/OR	1			-7.90		1.00
16	331.00 CA/OR	16,161			13.89		1.00
17	332.00 CA/OR	39,464			12.99		1.00
18	333.00 CA/OR	18,170			6.23		1.00
19	334.00 CA/OR	16,570			7.16		1.00
20	335.00 CA/OR	182			3.40		1.00
21	336.00 CA/OR	2,753			8.94		1.00
22							
23							
24							
25							
26							
27							
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Schedule Page: 336 Line No.: 1 Column: d

Adjustment to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, is as follows:

Functional Classification (a)	Ref. Line No. (Column)	Amort. of Ltd. Term Elec. Plt. (Acct 404) (d)
Intangible Plant	1(d)	$ 45,506,528
Less: Intangible mining plant(1)		2,705
Revised Intangible Plant		$ 45,503,823

(1) To adjust PacifiCorp's formula rate, per FERC Docket No. FA16-4-000 for amortization of mining assets related to production plant.

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, 2018, depreciation expense associated with transportation equipment was $15,829,896.

Schedule Page: 336 Line No.: 12 Column: e

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

Schedule Page: 336 Line No.: 13 Column: a

The depreciation rate changes are for the Klamath hydroelectric system’s four mainstem dams (JC Boyle, Iron Gate, Copco No. 1 and Copco No. 2). For further discussion, refer to Note 13 of Notes to Financial Statements, in this Form No. 1.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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	6,284,858		6,284,858	
3	Rate Cases and Proceedings		290,838	290,838	
4					
5	Oregon Public Utility Commission:				
6	Annual Fee	3,029,969		3,029,969	
7	Rate Cases and Proceedings		659,081	659,081	
8	Deferred Intervenor Funding Grants				535,508
9					
10	Wyoming Public Service Commission:				
11	Annual Fee	1,758,157		1,758,157	
12	Rate Cases and Proceedings		178,591	178,591	
13					
14	Washington Utilities and Transportation				
15	Commission:				
16	Annual Fee	659,957		659,957	
17	Rate Cases and Proceedings		38,413	38,413	
18					
19	Idaho Public Utilities Commission:				
20	Annual Fee	655,184		655,184	
21	Rate Cases and Proceedings		13,964	13,964	
22	Deferred Intervenor Funding Grants				26,865
23					
24	California Public Utilities Commission:				
25	Annual Fee	912		912	
26	Rate Cases and Proceedings		765,542	765,542	
27	Deferred Intervenor Funding Grants				41,019
28					
29	California Environmental Protection Agency:				
30	Industry Compliance Fee	121,363	7,980	129,343	
31					
32	Multi-State:				
33	Rate Cases and Proceedings		418,733	418,733	
34	Other Regulatory		1,401,281	1,401,281	
35					
36	Federal Energy Regulatory Commission:				
37	Annual Fee	2,288,389		2,288,389	
38	Annual Fee - Hydroelectric Plants	2,926,671		2,926,671	
39	Transmission Rate Cases		325,635	325,635	
40	Other Regulatory		658,843	658,843	
41					
42					
43					
44					
45					
46	TOTAL	17,725,460	4,758,901	22,484,361	603,392

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 2018/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
Electric	928	6,284,858					2
Electric	928	290,838					3
							4
							5
Electric	928	3,029,969					6
Electric	928	659,081					7
			391,443			926,951	8
							9
							10
Electric	928	1,758,157					11
Electric	928	178,591					12
							13
							14
							15
Electric	928	659,957					16
Electric	928	38,413					17
							18
							19
Electric	928	655,184					20
Electric	928	13,964					21
			40,000			66,865	22
							23
							24
Electric	928	912					25
Electric	928	765,542					26
			976			41,995	27
							28
							29
Electric	928	129,343					30
							31
							32
Electric	928	418,733					33
Electric	928	1,401,281					34
							35
							36
Electric	928	2,288,389					37
Electric	928	2,926,671					38
Electric	928	325,635					39
Electric	928	658,843					40
							41
							42
							43
							44
							45
		22,484,361	432,419			1,035,811	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 2018/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	A. Electric R, D & D Performed Internally:	
2	(3) Distribution	WestSmart Electric Vehicle Project
3		
4	(6) Other	Utah Sustainable Transportation and Energy Plan
5		
6	B. Electric R, D & D Performed Externally:	
7	(1) Research Support	Electric Power Research Institute
8		- Advancing Smart Inverter Integration in Utah
9		
10	(2) Research Support	Edison Electric Institute
11		- Avian Power Line Interaction Committee
12		
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $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
5,663		908	5,663		2
					3
322,676	1,417,466	107,908	1,740,142		4
					5
					6
					7
	250,000	908	250,000		8
					9
					10
13,613	4,420		18,033		11
					12
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Schedule Page: 352 Line No.: 2 Column: b

In December 2016, PacifiCorp was selected for a $4 million grant from the U.S. Department of Energy to install, operate and collect data on plug-in electric vehicle charging stations located on 1,500 miles of interstate across Utah, Idaho and Wyoming. A component of this program related to research, development and demonstration activities is to manage and design an electric grid to handle widespread electric vehicle charging requirements in collaboration with the University of Utah.

Schedule Page: 352 Line No.: 4 Column: b

The Utah Sustainable Transportation and Energy Plan was signed into law in March 2016. The Utah legislation established a five-year pilot program to provide up to $10 million annually of mandated funding for electric vehicle infrastructure and clean coal research, and authorized funding at the Utah Public Service Commission's discretion for solar development, utility-scale battery storage and other innovative technology, economic development and air quality initiatives.

Schedule Page: 352 Line No.: 11 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 2018/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	95,054,780		
4	Transmission	14,783,731		
5	Regional Market			
6	Distribution	34,091,180		
7	Customer Accounts	38,573,572		
8	Customer Service and Informational	6,548,333		
9	Sales			
10	Administrative and General	42,123,486		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	231,175,082		
12	Maintenance			
13	Production	46,706,822		
14	Transmission	11,907,130		
15	Regional Market			
16	Distribution	59,591,171		
17	Administrative and General	1,740,227		
18	TOTAL Maintenance (Total of lines 13 thru 17)	119,945,350		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	141,761,602		
21	Transmission (Enter Total of lines 4 and 14)	26,690,861		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	93,682,351		
24	Customer Accounts (Transcribe from line 7)	38,573,572		
25	Customer Service and Informational (Transcribe from line 8)	6,548,333		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	43,863,713		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	351,120,432		351,120,432
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

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Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru 47)			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	351,120,432		351,120,432
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	162,409,945		162,409,945
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	162,409,945		162,409,945
72	Plant Removal (By Utility Departments)			
73	Electric Plant	10,547,821		10,547,821
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	10,547,821		10,547,821
77	Other Accounts (Specify, provide details in footnote):			
78	Fuel Stock	5,316,261		5,316,261
79	Miscellaneous Other Income Deductions	485,975		485,975
80	Miscellaneous Non-Operating and Non-Utility	546,524		546,524
81	Charges to Affiliates	1,034,490		1,034,490
82				
83				
84				
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86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	7,383,250		7,383,250
96	TOTAL SALARIES AND WAGES	531,461,448		531,461,448

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 2018/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)	(61,870)	(60,555)	1,629,580	1,943,271
3	Net Sales (Account 447)	(205,629)	(237,729)	(583,231)	(643,620)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7	Energy Imbalance Market (Account 555)	(6,425,782)	12,383,299	(25,885,713)	(64,915,544)
8					
9					
10					
11					
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45					
46	TOTAL	(6,693,281)	12,085,015	(24,839,364)	(63,615,893)

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 2018/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch				133,397,813	MWh	12,146,144
2	Reactive Supply and Voltage	111,261,712	MWh	7,325,300	125,946,125	MWh	8,292,230
3	Regulation and Frequency Response	52,136,625	MWh	35,145,321	68,297,939	MWh	35,852,981
4	Energy Imbalance				189,478	MWh	46,495,236
5	Operating Reserve - Spinning	120,788,112	MWh	18,239,005	132,008,379	MWh	19,617,901
6	Operating Reserve - Supplement	120,788,112	MWh	18,239,005	132,120,404	MWh	19,029,503
7	Other						-4,742,969
8	Total (Lines 1 thru 7)	404,974,561		78,948,631	591,960,138		136,691,026

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

Refund for transmission services pursuant to FERC Docket No. ER17-219-002 and ER11-3643-000.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	15,295	2	1800	8,414	509	3,624		1,546	1,202
2	February	14,944	23	800	8,657	541	3,624		859	1,263
3	March	15,118	6	800	8,121	475	3,674		1,625	1,223
4	Total for Quarter 1				25,192	1,525	10,922		4,030	3,688
5	April	14,376	3	800	7,694	442	3,674		1,399	1,167
6	May	14,882	24	1700	7,929	303	3,674		1,605	1,371
7	June	18,094	27	1700	9,810	374	3,832		2,313	1,765
8	Total for Quarter 2				25,433	1,119	11,180		5,317	4,303
9	July	18,615	16	1700	10,708	434	3,832		1,736	1,905
10	August	18,128	9	1600	10,483	435	3,832		1,547	1,831
11	September	16,722	7	1700	9,090	345	3,832		1,803	1,652
12	Total for Quarter 3				30,281	1,214	11,496		5,086	5,388
13	October	14,524	2	1300	7,422	314	3,793		1,672	1,323
14	November	15,122	20	800	8,101	457	3,635		1,698	1,231
15	December	15,775	6	1800	8,558	520	3,635		1,729	1,333
16	Total for Quarter 4				24,081	1,291	11,063		5,099	3,887
17	Total Year to Date/Year				104,987	5,149	44,661		19,532	17,266

Schedule Page: 400 Line No.: 1 Column: d
Pacific Standard Time

Schedule Page: 400 Line No.: 2 Column: d
Pacific Standard Time

Schedule Page: 400 Line No.: 3 Column: d
Pacific Standard Time

Schedule Page: 400 Line No.: 5 Column: d
Pacific Daylight Time

Schedule Page: 400 Line No.: 6 Column: d
Pacific Daylight Time

Schedule Page: 400 Line No.: 7 Column: d
Pacific Daylight Time

Schedule Page: 400 Line No.: 9 Column: d
Pacific Daylight Time

Schedule Page: 400 Line No.: 10 Column: d
Pacific Daylight Time

Schedule Page: 400 Line No.: 11 Column: d
Pacific Daylight Time

Schedule Page: 400 Line No.: 13 Column: d
Pacific Daylight Time

Schedule Page: 400 Line No.: 14 Column: d
Pacific Standard Time

Schedule Page: 400 Line No.: 15 Column: d
Pacific Standard Time

Schedule Page: 400 Line No.: 17 Column: e
Year-to-date 2018 Net System Load information was compiled using metering and/or scheduling data. Reflects actual peak net system load for self at time of Transmission System Peak. Peak load includes behind-the-meter generation.

Schedule Page: 400 Line No.: 17 Column: f
Year-to-date 2018 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 2018 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 2018 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 2018 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 2018/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)	55,115,456
3	Steam	39,967,861			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	308,313
5	Hydro-Conventional	3,261,654			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	8,001,159
7	Other	10,276,271			
8	Less Energy for Pumping	4,251	25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	53,501,535	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	129,220
10	Purchases	13,668,425	27	Total Energy Losses	3,484,684
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	67,038,832
12	Received	7,967,992			
13	Delivered	7,994,889			
14	Net Exchanges (Line 12 minus line 13)	-26,897			
15	Transmission For Other (Wheeling)				
16	Received	16,159,593			
17	Delivered	16,047,747			
18	Net Transmission for Other (Line 16 minus line 17)	111,846			
19	Transmission By Others Losses	-216,077			
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	67,038,832			

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 2018/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	6,115,335	1,026,961	8,164	2	1800 PST
30	February	5,232,606	690,452	8,436	23	0800 PST
31	March	5,390,036	618,316	7,872	6	0800 PDT
32	April	4,950,593	570,863	7,446	3	0800 PDT
33	May	5,076,782	526,093	7,727	24	1800 PDT
34	June	5,548,195	555,267	9,584	27	1700 PDT
35	July	6,370,540	458,754	10,551	16	1700 PDT
36	August	6,055,886	534,799	10,263	9	1600 PDT
37	September	5,488,846	718,263	8,866	7	1700 PDT
38	October	5,450,455	901,565	7,250	1	2000 PDT
39	November	5,433,689	754,139	7,852	20	0800 PST
40	December	5,925,869	645,687	8,318	7	0800 PST
41	TOTAL	67,038,832	8,001,159			

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 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	Plant Name: 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)	380			157		
7	Plant Hours Connected to Load	6073			8297		
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	1916020000			947341000		
13	Cost of Plant: Land and Land Rights	2635317			1788644		
14	Structures and Improvements	65476965			62658945		
15	Equipment Costs	483537232			170719668		
16	Asset Retirement Costs	12698745			8509670		
17	Total Cost	564348259			243676927		
18	Cost per KW of Installed Capacity (line 17/5) Including	1363.1600			1565.9464		
19	Production Expenses: Oper, Supv, & Engr	2327801			46436		
20	Fuel	51138962			14844191		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	8142986			1147621		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	281070			61869		
26	Misc Steam (or Nuclear) Power Expenses	2374542			1799195		
27	Rents	0			23058		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	2820176			239276		
30	Maintenance of Structures	3861343			318886		
31	Maintenance of Boiler (or reactor) Plant	8099267			2633725		
32	Maintenance of Electric Plant	1958604			324986		
33	Maintenance of Misc Steam (or Nuclear) Plant	1544014			425069		
34	Total Production Expenses	82548765			21864312		
35	Expenses per Net KWh	0.0431			0.0231		
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	1122843	2913	0	605618	1734	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9191	129293	0	8481	140000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	44.253	93.360	0.000	21.674	96.596	0.000
41	Average Cost of Fuel per Unit Burned	45.302	93.360	0.000	24.234	96.596	0.000
42	Average Cost of Fuel Burned per Million BTU	2.464	17.193	2.476	1.429	16.428	1.444
43	Average Cost of Fuel Burned per KWh Net Gen	0.027	0.000	0.027	0.015	0.000	0.015
44	Average BTU per KWh Net Generation	10772.367	8.256	10780.623	10843.242	10.762	10854.004

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 2018/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: *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
163			754			78			6
8760			8760			8760			7
0			0			0			8
161			751			77			9
0			0			0			10
0			189			0			11
1201526000			4800371000			474063000			12
137086			10449793			683069			13
38586351			159752557			17795743			14
184905599			875125839			96364150			15
35149			15492309			511486			16
223664185			1060820498			115354448			17
1299.3911			1298.7995			1417.6533			18
391931			21188			335266			19
23904488			54519018			11428283			20
0			0			0			21
1899748			3083282			974138			22
0			0			0			23
0			0			0			24
739568			0			464607			25
1071430			15866745			412169			26
1000			99555			0			27
0			0			0			28
728272			0			119291			29
508901			2295638			487284			30
2924297			11068547			1417576			31
660655			10790684			1106808			32
775764			703556			349021			33
33606054			98448213			17094443			34
0.0280			0.0205			0.0361			35
Coal	Oil	Composite	Coal	Oil	Composite	Coal	Oil	Composite	36
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
642447	59	0	3310165	13075	0	222992	301	0	38
9880	133434	0	8244	138000	0	11277	137269	0	39
31.109	103.260	0.000	16.188	106.926	0.000	44.801	94.186	0.000	40
37.065	103.260	0.000	16.048	106.926	0.000	51.043	94.186	0.000	41
1.876	18.443	1.883	0.973	18.448	0.997	2.263	16.339	2.272	42
0.020	0.000	0.020	0.011	0.000	0.011	0.024	0.000	0.024	43
10565.168	0.276	10565.444	11369.954	15.787	11385.741	10608.634	3.656	10612.290	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: 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)			421			271
7	Plant Hours Connected to Load			7138			8214
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			2356979000			1810269000
13	Cost of Plant: Land and Land Rights			9688261			9688261
14	Structures and Improvements			64971404			54346329
15	Equipment Costs			388748500			246956656
16	Asset Retirement Costs			4278309			4278309
17	Total Cost			467686474			315269555
18	Cost per KW of Installed Capacity (line 17/5) Including			1021.7518			1070.6702
19	Production Expenses: Oper, Supv, & Engr			-1221			-786
20	Fuel			46389882			34186040
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			6514688			5180561
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			-44182			76607
26	Misc Steam (or Nuclear) Power Expenses			1047416			-3374347
27	Rents			0			0
28	Allowances			0			0
29	Maintenance Supervision and Engineering			0			0
30	Maintenance of Structures			1814729			987501
31	Maintenance of Boiler (or reactor) Plant			9672902			3955715
32	Maintenance of Electric Plant			4482499			1032159
33	Maintenance of Misc Steam (or Nuclear) Plant			386953			279662
34	Total Production Expenses			70263666			42323112
35	Expenses per Net KWh			0.0298			0.0234
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	1076602	2705	0	799867	2144	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11321	138000	0	11518	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	42.838	0.000	0.000	42.470	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	1.892	17.219	1.902	1.844	17.347	1.854
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	10342.504	6.651	10349.155	10178.802	6.865	10185.667

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

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

Plant Name: *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
480			1366			907			6
8426			8760			8618			7
0			0			0			8
471			1158			909			9
0			0			0			10
0			214			158			11
2954132000			7121380000			5087824000			12
10274569			29651091			2377564			13
93037673			212355406			125725785			14
447605400			1083310556			749858203			15
4278309			12834927			10162682			16
555195951			1338151980			888124234			17
1120.2727			1072.4262			891.6910			18
-1376			-3383			7601			19
57000166			137576088			125760156			20
0			0			0			21
7537492			19232741			10745267			22
0			0			0			23
0			0			0			24
-47170			-14745			0			25
2659661			332730			7992603			26
0			0			1574			27
0			0			0			28
0			0			1724730			29
1422247			4224477			2362818			30
5106595			18735212			14177302			31
665760			6180418			4665426			32
575191			1241806			752946			33
74918566			187505344			168190423			34
0.0254			0.0263			0.0331			35
Coal	Oil	Composite	Coal	Oil	Composite	Coal	Oil	Composite	36
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
1307413	12340	0	3183882	17189	0	2317991	7888	0	38
11241	138000	0	11338	138000	0	11499	138000	0	39
0.000	0.000	0.000	42.296	102.297	0.000	52.728	101.694	0.000	40
42.624	0.000	0.000	42.658	102.297	0.000	53.908	101.694	0.000	41
1.896	17.796	1.935	1.881	17.649	1.903	2.344	17.546	2.357	42
0.019	0.000	0.019	0.019	0.000	0.019	0.025	0.000	0.025	43
9949.490	24.211	9973.701	10137.859	13.990	10151.849	10478.037	8.986	10487.023	44

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

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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)			1422			650
7	Plant Hours Connected to Load			8760			8760
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			334			127
12	Net Generation, Exclusive of Plant Use - KWh			8454799000			4740078000
13	Cost of Plant: Land and Land Rights			1193761			1321031
14	Structures and Improvements			147793420			126677607
15	Equipment Costs			1261996800			676575672
16	Asset Retirement Costs			18173604			49036301
17	Total Cost			1429157585			853610611
18	Cost per KW of Installed Capacity (line 17/5) Including			921.6507			1207.0286
19	Production Expenses: Oper, Supv, & Engr			14244410			432464
20	Fuel			252789422			115283027
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			19732163			11709432
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			0			6015
26	Misc Steam (or Nuclear) Power Expenses			-22794898			8357145
27	Rents			327809			14350
28	Allowances			0			0
29	Maintenance Supervision and Engineering			882154			1473533
30	Maintenance of Structures			11129738			1179901
31	Maintenance of Boiler (or reactor) Plant			24298890			6003999
32	Maintenance of Electric Plant			10735807			1530777
33	Maintenance of Misc Steam (or Nuclear) Plant			2159453			887053
34	Total Production Expenses			313504948			146877696
35	Expenses per Net KWh			0.0371			0.0310
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	4780005	11405	0	2595814	88860	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9275	138000	0	9961	1048	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	47.987	92.338	0.000	44.550	5.968	0.000
41	Average Cost of Fuel per Unit Burned	52.664	92.338	0.000	44.207	5.968	0.000
42	Average Cost of Fuel Burned per Million BTU	2.839	15.931	2.849	2.219	5.694	2.225
43	Average Cost of Fuel Burned per KWh Net Gen	0.030	0.000	0.030	0.024	0.000	0.024
44	Average BTU per KWh Net Generation	10487.380	7.819	10495.199	10909.721	19.649	10929.370

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

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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
140.29	251.64	279.56	5
270	167	248	6
8218	926	7839	7
0	0	0	8
266	238	231	9
0	0	0	10
62	33	0	11
1741620000	51636000	1472457000	12
210526	1252090	796929	13
52275645	15331406	12843088	14
410185493	68969911	165198033	15
279518	1132809	407646	16
462951182	86686216	179245696	17
3299.9585	344.4850	641.1708	18
17194	18134	0	19
27048098	3248365	28887840	20
0	0	0	21
3663968	96246	0	22
0	0	0	23
0	0	0	24
0	0	7211303	25
3474225	3360741	0	26
13719	0	0	27
0	0	0	28
0	0	0	29
247015	95587	0	30
3666252	1098593	0	31
1142523	1097467	0	32
160172	137581	0	33
39433166	9152714	36099143	34
0.0226	0.1773	0.0245	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Coal	Oil	Composite	Gas			Gas			36
Tons	Barrels		MCF			MCF			37
1393744	3395	0	894072	0	0	10984079	0	0	38
8032	138000	0	1040	0	0	1022	0	0	39
19.016	88.443	0.000	3.633	0.000	0.000	2.630	0.000	0.000	40
19.191	88.443	0.000	3.633	0.000	0.000	2.630	0.000	0.000	41
1.195	15.259	1.207	3.495	0.000	0.000	2.573	0.000	0.000	42
0.015	0.000	0.015	0.063	0.000	0.000	0.020	0.000	0.000	43
12855.726	11.300	12867.026	17998.896	0.000	0.000	7624.810	0.000	0.000	44

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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)	35			506		
7	Plant Hours Connected to Load	8544			5575		
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	21			19		
12	Net Generation, Exclusive of Plant Use - KWh	223051000			1741969000		
13	Cost of Plant: Land and Land Rights	41195596			3730527		
14	Structures and Improvements	8338030			24474663		
15	Equipment Costs	102923431			328950227		
16	Asset Retirement Costs	2391759			1030777		
17	Total Cost	154848816			358186194		
18	Cost per KW of Installed Capacity (line 17/5) Including	4064.2734			603.7185		
19	Production Expenses: Oper, Supv, & Engr	8081			126746		
20	Fuel	0			26546969		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	225718			0		
23	Steam From Other Sources	4714446			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			1948752		
26	Misc Steam (or Nuclear) Power Expenses	2126361			641474		
27	Rents	7560			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	237793			37024		
31	Maintenance of Boiler (or reactor) Plant	120536			0		
32	Maintenance of Electric Plant	283273			2266933		
33	Maintenance of Misc Steam (or Nuclear) Plant	100914			0		
34	Total Production Expenses	7824682			31567898		
35	Expenses per Net KWh	0.0351			0.0181		
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	11805959	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	1099	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	2.249	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	2.249	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	2.046	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.015	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	7446.740	0.000	0.000

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

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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
124			540			520			6
492			7358			6166			7
0			0			0			8
119			524			546			9
0			0			0			10
0			18			32			11
8046000			2418275000			1839453000			12
0			3403277			14532275			13
4263913			44250508			35509712			14
81389845			307242254			339338282			15
0			134848			0			16
85653758			355030887			389380269			17
473.0945			626.2672			658.5156			18
0			62684			44613			19
1435967			59493080			48493424			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
768281			1825911			2107000			25
0			677960			516622			26
0			0			0			27
0			0			0			28
0			0			0			29
95220			688422			1344667			30
0			0			0			31
375490			1140634			529726			32
142655			54855			30000			33
2817613			63943546			53066052			34
0.3502			0.0264			0.0288			35
Gas			Gas			Gas			36
MCF			MCF			MCF			37
133908	0	0	17337641	0	0	13326731	0	0	38
1039	0	0	1040	0	0	1039	0	0	39
10.724	0.000	0.000	3.431	0.000	0.000	3.639	0.000	0.000	40
10.724	0.000	0.000	3.431	0.000	0.000	3.639	0.000	0.000	41
10.324	0.000	0.000	3.300	0.000	0.000	3.503	0.000	0.000	42
0.178	0.000	0.000	0.025	0.000	0.000	0.026	0.000	0.000	43
17286.726	0.000	0.000	7455.298	0.000	0.000	7525.434	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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

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

Line No.	Item (a)	Plant Name: *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)	639			0		
7	Plant Hours Connected to Load	7472			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	3021716000			0		
13	Cost of Plant: Land and Land Rights	16794626			0		
14	Structures and Improvements	53124296			0		
15	Equipment Costs	569854794			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	639773716			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	976.4556			0		
19	Production Expenses: Oper, Supv, & Engr	51559			0		
20	Fuel	74274535			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	3542172			0		
26	Misc Steam (or Nuclear) Power Expenses	603508			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	2231623			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	2865016			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	33641			0		
34	Total Production Expenses	83602054			0		
35	Expenses per Net KWh	0.0277			0.0000		
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	21258527	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	3.494	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	3.494	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.364	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.025	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	7306.212	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 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 represents PacifiCorp's share.

Schedule Page: 403 Line No.: -1 Column: d

The Craig Plant is operated by Tri-State Generation and Transmission Association, Inc. 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 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 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 represents PacifiCorp's share. Costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this unit for calendar year 2018 were $2.0 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 represents PacifiCorp's share. Costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this unit for calendar year 2018 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 Hunter Unit Nos. 1, 2 and 3 for each unit's plant statistics.

Schedule Page: 402.1 Line No.: 11 Column: b

Refer to Hunter - Total Plant for the average number of employees.

Schedule Page: 402.1 Line No.: 11 Column: c

Refer to Hunter - Total Plant for the average number of employees.

Schedule Page: 403.1 Line No.: 11 Column: d

Refer to Hunter - Total Plant 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 66.67% and 33.33%, respectively. Data reported represents PacifiCorp's share. Costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this plant for calendar year 2018 were $33.7 million and were primarily credited to Account 506, Miscellaneous steam power expenses.

Schedule Page: 402.2 Line No.: -1 Column: c

On January 30, 2019, Naughton Unit No. 3 (280 MW) a coal-fueled generating plant, was removed from service due to state permits. Currently, PacifiCorp is evaluating the economic benefits of converting the Naughton Unit No. 3 to a natural gas-fueled generation resource.

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 represents PacifiCorp's share. Costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this plant for calendar year 2018 were $4.0 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 represents PacifiCorp's share.

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 for the average number of employees.

Schedule Page: 402.4 Line No.: 11 Column: b

Refer to the Lake Side Plant 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.

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 2018/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	33
7	Plant Hours Connect to Load	4,946	4,895
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	73,916,000	92,720,000
13	Cost of Plant		
14	Land and Land Rights	107,019	20,914
15	Structures and Improvements	1,774,794	2,457,315
16	Reservoirs, Dams, and Waterways	3,357,158	2,965,439
17	Equipment Costs	5,679,214	10,488,152
18	Roads, Railroads, and Bridges	133,348	551,687
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	11,051,533	16,483,507
21	Cost per KW of Installed Capacity (line 20 / 5)	552.5767	610.5003
22	Production Expenses		
23	Operation Supervision and Engineering	10,712	15,900
24	Water for Power	0	0
25	Hydraulic Expenses	1,534	2,071
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	1,062,803	1,269,691
28	Rents	55,925	75,499
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	6,612	2,835
31	Maintenance of Reservoirs, Dams, and Waterways	36,523	1,604
32	Maintenance of Electric Plant	27,523	93,146
33	Maintenance of Misc Hydraulic Plant	20,285	27,385
34	Total Production Expenses (total 23 thru 33)	1,221,917	1,488,131
35	Expenses per net KWh	0.0165	0.0160

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 2018/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	12	30	6
8,757	8,355	5,772	7
			8
18	31	29	9
18	31	29	10
1	1	3	11
40,494,000	36,927,000	69,760,000	12
			13
0	0	3,511,105	14
1,504,709	2,449,890	4,042,960	15
5,184,972	14,819,998	10,073,946	16
1,407,668	2,197,848	15,037,762	17
50,817	250,151	569,655	18
0	0	0	19
8,148,166	19,717,887	33,235,428	20
543.2111	758.3803	1,107.8476	21
			22
10,630	19,439	114,749	23
812	1,407	0	24
41,891	72,611	118,394	25
0	0	0	26
283,766	459,560	1,318,206	27
48,426	83,938	-11,112	28
0	0	0	29
25,412	43,622	0	30
7,482	10,589	26,358	31
9,990	132,829	5,835	32
33,914	58,784	446,423	33
462,323	882,779	2,018,853	34
0.0114	0.0239	0.0289	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 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 1927 Plant Name: Fish Creek (b)	FERC Licensed Project No. 20 Plant Name: Grace (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1952	1908
4	Year Last Unit was Installed	1952	1923
5	Total installed cap (Gen name plate Rating in MW)	11.00	33.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	10	29
7	Plant Hours Connect to Load	2,714	8,336
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	10	33
10	(b) Under the Most Adverse Oper Conditions	10	33
11	Average Number of Employees	1	4
12	Net Generation, Exclusive of Plant Use - Kwh	14,758,000	123,892,000
13	Cost of Plant		
14	Land and Land Rights	0	62,169
15	Structures and Improvements	1,764,792	2,934,991
16	Reservoirs, Dams, and Waterways	12,459,236	11,561,657
17	Equipment Costs	2,993,343	5,343,471
18	Roads, Railroads, and Bridges	533,015	499,327
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	17,750,386	20,401,615
21	Cost per KW of Installed Capacity (line 20 / 5)	1,613.6715	618.2308
22	Production Expenses		
23	Operation Supervision and Engineering	6,719	132,149
24	Water for Power	595	0
25	Hydraulic Expenses	30,720	42,856
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	254,569	1,317,793
28	Rents	35,512	-3,439
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	19,678	11,335
31	Maintenance of Reservoirs, Dams, and Waterways	10,651	72,456
32	Maintenance of Electric Plant	54,001	32,524
33	Maintenance of Misc Hydraulic Plant	24,870	53,616
34	Total Production Expenses (total 23 thru 33)	437,315	1,659,290
35	Expenses per net KWh	0.0296	0.0134

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 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2082 Plant Name: Iron Gate (d)	FERC Licensed Project No. 2082 Plant Name: JC Boyle (e)	FERC Licensed Project No. 1927 Plant Name: Lemolo No. 1 (f)	Line No.
Storage	Storage	Storage	1
Outdoor	Outdoor	Outdoor	2
1962	1958	1955	3
1962	1958	1955	4
18.00	97.98	31.99	5
19	85	32	6
8,655	5,276	8,710	7
			8
19	83	32	9
19	83	32	10
1	2	1	11
88,987,000	194,050,000	124,864,000	12
			13
341,617	25,845	0	14
8,175,609	3,731,330	2,940,403	15
17,240,484	15,899,073	15,807,219	16
3,150,391	15,603,261	6,726,791	17
1,095,742	972,360	484,094	18
0	0	0	19
30,003,843	36,231,869	25,958,507	20
1,666.8802	369.7884	811.4569	21
			22
1,584,515	162,361	18,954	23
0	0	1,731	24
1,381	7,417	89,340	25
0	0	0	26
989,730	810,557	674,580	27
50,333	1,873	103,276	28
0	0	0	29
1,888	17,209	80,309	30
23,067	93,244	13,262	31
8,027	51,291	28,315	32
18,256	36,954	72,327	33
2,677,197	1,180,906	1,082,094	34
0.0301	0.0061	0.0087	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 2018/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)	31	149
7	Plant Hours Connect to Load	7,982	8,759
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	133,034,000	450,459,000
13	Cost of Plant		
14	Land and Land Rights	0	1,735,054
15	Structures and Improvements	6,295,797	110,619,342
16	Reservoirs, Dams, and Waterways	32,875,543	30,506,980
17	Equipment Costs	11,847,637	18,925,111
18	Roads, Railroads, and Bridges	1,820,580	4,140,268
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	52,839,557	165,926,755
21	Cost per KW of Installed Capacity (line 20 / 5)	1,372.4560	1,220.0497
22	Production Expenses		
23	Operation Supervision and Engineering	22,812	1,458,874
24	Water for Power	2,083	2,420
25	Hydraulic Expenses	107,520	878,055
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	596,292	541,499
28	Rents	124,293	107,560
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	64,310	43,894
31	Maintenance of Reservoirs, Dams, and Waterways	119,649	47,405
32	Maintenance of Electric Plant	202,519	138,578
33	Maintenance of Misc Hydraulic Plant	87,045	581,301
34	Total Production Expenses (total 23 thru 33)	1,326,523	3,799,586
35	Expenses per net KWh	0.0100	0.0084

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 2018/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
39	20	36	6
8,758	8,679	8,701	7
			8
45	28	36	9
45	28	36	10
1	2	1	11
195,057,000	61,899,000	199,202,000	12
			13
0	283,870	105,168	14
4,379,946	2,330,393	4,074,730	15
12,847,979	8,532,515	35,357,614	16
5,661,905	12,747,634	7,362,752	17
502,952	661,547	324,746	18
0	0	0	19
23,392,782	24,555,959	47,225,010	20
550.4184	818.5320	1,475.7816	21
			22
30,456	111,944	259,677	23
2,300	0	11,058	24
118,694	38,960	2,422	25
0	0	0	26
750,704	643,336	628,714	27
137,210	-3,581	8,054	28
0	0	321	29
84,144	628	65,757	30
10,547	1,358	125,189	31
107,407	46,103	88,518	32
96,091	61,993	262,964	33
1,337,553	900,741	1,452,674	34
0.0069	0.0146	0.0073	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 2018/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)	14	9
7	Plant Hours Connect to Load	8,734	6,583
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	56,868,000	29,789,000
13	Cost of Plant		
14	Land and Land Rights	0	511,083
15	Structures and Improvements	2,213,290	782,666
16	Reservoirs, Dams, and Waterways	14,884,883	11,108,268
17	Equipment Costs	8,978,529	5,420,920
18	Roads, Railroads, and Bridges	599,269	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	26,675,971	17,822,937
21	Cost per KW of Installed Capacity (line 20 / 5)	1,481.9984	1,233.4212
22	Production Expenses		
23	Operation Supervision and Engineering	12,274	52,240
24	Water for Power	3,618	0
25	Hydraulic Expenses	50,269	18,181
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	313,139	326,605
28	Rents	58,111	-1,590
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	47,101	64
31	Maintenance of Reservoirs, Dams, and Waterways	23,853	1,335
32	Maintenance of Electric Plant	32,313	17,372
33	Maintenance of Misc Hydraulic Plant	40,697	22,608
34	Total Production Expenses (total 23 thru 33)	581,375	436,815
35	Expenses per net KWh	0.0102	0.0147

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 2018/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	241	167	6
8,757	5,352	6,157	7
			8
12	264	164	9
12	264	164	10
2	1	1	11
44,108,000	545,383,000	519,637,000	12
			13
0	17,912,070	8,363,013	14
4,307,766	71,629,227	17,792,675	15
90,253,682	47,515,885	33,765,145	16
2,635,457	24,895,858	16,988,507	17
2,089,012	1,319,865	2,045,631	18
0	0	0	19
99,285,917	163,272,905	78,954,971	20
9,025.9925	680.3038	589.2162	21
			22
6,819	2,398,400	1,374,491	23
595	4,271	2,385	24
175,155	1,762,545	862,592	25
0	0	0	26
411,117	406,456	488,969	27
35,512	189,584	105,851	28
0	0	0	29
18,350	52,108	38,976	30
93,544	75,010	66,064	31
6,482	176,265	111,478	32
24,870	986,325	559,586	33
772,444	6,050,964	3,610,392	34
0.0175	0.0111	0.0069	35

Schedule Page: 406 Line No.: -2 Column: b

In FERC Order No. P-14803-000 (issued March 15, 2018), articles pertaining to this hydroelectric plant were transferred from the Klamath (FERC License) Project No. 2082 to a new license for the Lower Klamath Project No. 14803. For further discussion, refer to Note 13 of Notes to Financial Statements, in this Form No. 1.

Schedule Page: 406 Line No.: -2 Column: c

In FERC Order No. P-14803-000 (issued March 15, 2018), articles pertaining to this hydroelectric plant were transferred from the Klamath (FERC License) Project No. 2082 to a new license for the Lower Klamath Project No. 14803. For further discussion, refer to Note 13 of Notes to Financial Statements, in this Form No. 1.

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.: -2 Column: d

In FERC Order No. P-14803-000 (issued March 15, 2018), articles pertaining to this hydroelectric plant were transferred from the Klamath (FERC License) Project No. 2082 to a new license for the Lower Klamath Project No. 14803. For further discussion, refer to Note 13 of Notes to Financial Statements, in this Form No. 1.

Schedule Page: 406.1 Line No.: -2 Column: e

In FERC Order No. P-14803-000 (issued March 15, 2018), articles pertaining to this hydroelectric plant were transferred from the Klamath (FERC License) Project No. 2082 to a new license for the Lower Klamath Project No. 14803. For further discussion, refer to Note 13 of Notes to Financial Statements, in this Form No. 1.

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	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2018/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	38,064,000	34,009,021
3	Bend		1913	1.11	1.0	1,448,000	2,326,593
4	Big Fork	2652	1910	4.15	4.6	26,131,000	9,684,965
5	Eagle Point		1957	2.81	2.8	16,411,000	2,011,829
6	East Side	2082	1924	3.20			1,991,695
7	Fall Creek	2082	1903	2.20	2.0	3,931,000	2,112,218
8	Granite		1896	2.00	1.3	5,359,000	5,261,282
9	Gunlock		1917	0.75	0.4	663,000	683,045
10	Last Chance		1983	1.73	1.3	4,553,000	3,132,443
11	Paris	703	1910	0.72	0.7	2,455,000	459,985
12	Pioneer	2722	1897	5.00	2.7	9,235,000	11,548,276
13	Prospect No. 1	2630	1912	3.76	4.6	12,114,000	5,344,452
14	Prospect No. 3	2337	1932	7.20	7.7	22,263,000	9,134,363
15	Prospect No. 4	2630	1944	1.00	0.9	2,541,000	2,409,792
16	Sand Cove		1926	0.80	0.4	471,000	939,281
17	Stairs	597	1895	1.00	1.2	3,766,000	1,953,373
18	Veyo		1920	0.50			899,180
19	Viva Naughton		1986	0.74	0.2	509,000	1,232,115
20	Wallowa Falls	308	1921	1.10	1.0	4,664,000	3,282,375
21	Weber	1744	1911	3.85	2.0	11,273,000	3,877,478
22	West Side	2082	1908	0.60		-1,000	489,350
23	Keno Regulating Dam	2082					7,684,061
24	Upper Klamath Lake	2082					3,847,587
25	North Umpqua	1927					16,931,391
26							
27	Pumping Plant:						
28	Lifton		1917	-2.80	-2.0	-4,251,000	19,532,260
29							
30	Wind:						
31	Dunlap Ranch 1		2010	111.00	111.0	391,874,000	242,003,550
32	Foote Creek		1999	32.15	31.4	104,801,000	38,185,620
33	Glenrock		2008	99.00	99.0	303,865,000	202,915,370
34	Glenrock III		2009	39.00	39.0	117,589,000	88,354,617
35	Rolling Hills		2009	99.00	99.0	277,843,000	204,806,286
36	Goodnoe Hills		2008	94.00	93.0	230,513,000	185,587,277
37	Leaning Juniper 1		2006	100.00	100.0	201,665,000	179,254,420
38	Marengo		2007	140.40	132.0	336,426,000	242,815,922
39	Marengo II		2008	70.20	68.0	164,436,000	130,336,135
40	Seven Mile Hill		2008	99.00	99.0	348,285,000	201,875,938
41	Seven Mile Hill II		2008	19.50	19.5	73,738,000	42,718,778
42	High Plains		2009	99.00	99.0	327,035,000	220,691,336
43	McFadden Ridge I		2009	28.50	28.5	100,324,000	57,381,213
44							
45	Solar:						
46	Black Cap		2012	2.00	2.0	4,113,000	74,986

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 2018/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
5,075,973	444,252		134,798	Water		2
2,096,030	95,041		42,971	Water		3
2,333,727	315,476		65,349	Water		4
715,953	264,668		111,666	Water		5
622,405	47,027		5,437	Water		6
960,099	137,333		17,370	Water		7
2,630,641	187,994		-5,143	Water		8
910,727	49,770		70,178	Water		9
1,810,661	182,633		14,058	Water		10
638,868	69,060		9,616	Water		11
2,309,655	493,215		75,013	Water		12
1,421,397	117,563		70,656	Water		13
1,268,662	242,552		261,016	Water		14
2,409,792	40,764		29,181	Water		15
1,174,101	59,774		60,629	Water		16
1,953,373	203,706		9,883	Water		17
1,798,360	74,495		212,980	Water		18
1,665,020	88,273		21,577	Water		19
2,983,977	261,492		13,880	Water		20
1,007,137	351,561		19,164	Water		21
815,583	9,860		322	Water		22
	21,652		8,184			23
	267,236		48,559			24
						25
						26
						27
-6,975,807	255,670		25,083	Water		28
						29
						30
2,180,212	237,653		1,173,502	Wind		31
1,187,733	429,264		1,316,345	Wind		32
2,049,650	226,080		1,557,499	Wind		33
2,265,503	92,455		249,637	Wind		34
2,068,750	212,518		633,695	Wind		35
1,974,333	577,377		1,130,320	Wind		36
1,792,544	1,064,517		946,663	Wind		37
1,729,458	1,254,830		1,195,256	Wind		38
1,856,640	636,941		597,628	Wind		39
2,039,151	478,611		1,102,825	Wind		40
2,190,707	89,232		217,223	Wind		41
2,229,205	1,023,684		1,231,800	Wind		42
2,013,376	289,264		339,358	Wind		43
						44
						45
37,493	416,670			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

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.: 18 Column: a

The Veyo plant generation was curtailed in 2018 due to a decline in water resources.

Schedule Page: 410 Line No.: 22 Column: a

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

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

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

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

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

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 represents PacifiCorp's share.

Schedule Page: 410 Line No.: 46 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.

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 2018/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								
2	ALVEY, OR	DIXONVILLE 500kV, OR	500.00	500.00	Steel Tower	58.00		1
3	CAPTAIN JACK, OR	MALIN, OR	500.00	500.00	Steel Tower	7.00		1
4	DIXONVILLE, OR	MERIDIAN, OR	500.00	500.00	Steel Tower	74.00		1
5	KLAMATH CO-GEN, OR	CAPTAIN JACK, OR	500.00	500.00	Steel Tower	26.00		1
6	MALIN, OR	PG&E ROUND MTN, CA	500.00	500.00	Steel Tower	47.00		1
7	MERIDIAN, OR	KLAMATH CO-GEN, OR	500.00	500.00	Steel Tower	58.00		1
8	MIDPOINT, ID	MALIN, OR	500.00	500.00	Steel Tower	447.00		1
9	COLSTRIP 4, MT	SWITCHYARD, MT	500.00	500.00	Steel Tower	2.00		1
10	COLSTRIP, MT	BROADVIEW A, MT	500.00	500.00	Steel Tower	112.00		1
11	COLSTRIP, MT	BROADVIEW B, MT	500.00	500.00	Steel Tower	116.00		1
12	BROADVIEW, MT	TOWNSEND A, MT	500.00	500.00	Steel Tower	133.00		1
13	BROADVIEW, MT	TOWNSEND B, MT	500.00	500.00	Steel Tower	133.00		1
14	500kV costs and expenses							
15	Subtotal 500kV					1,213.00		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	BEN LOMOND, UT	POPULUS #1, ID	345.00	345.00			82.00	1
22	BEN LOMOND, UT	POPULUS #2, ID	345.00	345.00	Steel - SP	86.00		1
23	BEN LOMOND, UT	CAMP WILLIAMS, UT	345.00	345.00	Steel - SP	69.00		1
24	BEN LOMOND, UT	TERMINAL #2, UT	345.00	345.00		47.00		1
25	BEN LOMOND, UT	TERMINAL #1, UT	345.00	345.00	Steel - SP		47.00	1
26	BORAH, ID	MIDPOINT #1, ID	345.00	345.00	Wood - H	83.00		1
27	BORAH, ID	MIDPOINT #2, ID	345.00	345.00	Wood - H	78.00		1
28	CAMP WILLIAMS, UT	MONA #3, UT	345.00	345.00	Wood - H	47.00		1
29	CAMP WILLIAMS, UT	MONA #1, UT	345.00	345.00	Wood - H	47.00		1
30	CAMP WILLIAMS, UT	MONA #2, UT	345.00	345.00	Steel Tower	47.00		1
31	CAMP WILLIAMS, UT	MONA #4 UT	345.00	345.00		5.00	42.00	1
32	CLOVER, UT	OQUIRRH, UT	345.00	345.00	Steel Tower	100.00		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	16,928.00	651.00	285

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 2018/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)	
								1
3-2250 AAC /91								2
3-1272 ACSR 36/1								3
3-1272 ACSR 36/1								4
3-1272 ACSR 54/19								5
3-1852 ACSR 51/27								6
3-1272 ACSR 54/19								7
3-1272 ACSR 36/1								8
795 KCM ACSR								9
795 ACSR 26/7								10
795 ACSR 26/7								11
795 ACSR 26/7								12
795 ACSR 26/7								13
	13,339,699	237,124,882	250,464,581	449	1,463,566	330,667	1,794,682	14
	13,339,699	237,124,882	250,464,581	449	1,463,566	330,667	1,794,682	15
								16
								17
								18
1272 ACSR 45/7								19
1272 ACSR 45/7								20
1272 ACSR 45/7								21
1272 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
954 ACSR 45/7								28
1272 ACSR 45/7								29
954 ACSR 45/7								30
954 ACSR 45/7								31
1949 ACSR 45/7								32
954 ACSR 54/7								33
1272 ACSR 45/7								34
954 ACSR 45/7								35
	245,939,765	3,522,864,268	3,768,804,033	864,557	16,229,553	2,138,345	19,232,455	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 2018/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 (Pole miles) On Structures of Another Line (g)	Number Of Circuits (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	101.00		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	GOSHEN, ID	345.00	345.00	Steel Tower	220.00		1
10	JIM BRIDGER, WY	BORAH, ID	345.00	345.00	Steel Tower	240.00		1
11	JIM BRIDGER, WY	KINPORT, ID	345.00	345.00	Steel - SP	234.00		1
12	KINPORT, ID	MIDPOINT, ID	345.00	345.00	Steel - SP	113.00		1
13	MONA, UT	SIGURD #1, UT	345.00	345.00	Wood - H	69.00		1
14	MONA, UT	SIGURD #2, UT	345.00	345.00	Steel - SP		69.00	1
15	MONA, UT	HUNTINGTON, UT	345.00	345.00	Steel - SP	60.00		1
16	RED BUTTE, UT	SIGURD, UT	345.00	345.00	Steel - H	170.00		1
17	SIGURD, UT	UT/NV STATE LINE	345.00	345.00	Steel Tower	190.00		1
18	SPANISH FORK, UT	CAMP WILLIAMS, UT	345.00	345.00			35.00	1
19	TERMINAL, UT	BORAH, ID	345.00	345.00	Wood - H	138.00		1
20	TERMINAL, UT	BORAH, ID	345.00	345.00	Steel - SP		47.00	1
21	TERMINAL, UT	CAMP WILLIAMS #2, UT	345.00	345.00	Steel - SP	16.00	10.00	1
22	TERMINAL, UT	CAMP WILLIAMS, UT	345.00	345.00			23.00	1
23	345kV costs and expenses							
24	Subtotal 345kV					2,752.00	382.00	41
25								
26	ALVEY, OR	DIXONVILLE, OR	230.00	230.00	Wood - H	59.00		1
27	ANTELOPE, ID	ANACONDA, MT	230.00	230.00	Wood - H	76.00		1
28	ANTELOPE, ID	LOST RIVER, ID	230.00	230.00	Wood - H	20.00		1
29	ARROWHEAD, WY	FIREHOLE, WY	230.00	230.00	Wood - H	9.00		1
30	ATLANTIC CITY, WY	COLUMBIA GENEVA, WY	230.00	230.00	Wood - H	1.00		1
31	BEN LOMOND, UT	NAUGHTON #1, WY	230.00	230.00	Wood - H	88.00		1
32	BEN LOMOND, UT	NAUGHTON #2, WY	230.00	230.00	Wood - H	88.00		1
33	BIRCH CREEK, UT	RAILROAD, WY	230.00	230.00	Wood - H	19.00		1
34	BITTER CREEK, WY	MONELL, WY	230.00	230.00	Wood - H	3.00		1
35	BRIDGER PUMP, WY	MANS FACE, WY	230.00	230.00	Wood - H	1.00		1
36					TOTAL	16,928.00	651.00	285

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
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
1272 ACSR 36/1								11
1272 ACSR 45/7								12
795 ACSR 45/7								13
954 ACSR 45/7								14
954 ACSR 54/7								15
2-954 ACSR 45/7								16
954 ACSR 54/7								17
1272 ACSR 45/7								18
2-954 ACSR 45/7								19
2-1272 ACSR 45/7								20
1272 ACSR 45/7								21
1272 ACSR 45/7								22
	152,615,169	1,659,942,000	1,812,557,169	339,884	2,022,182	521,772	2,883,838	23
	152,615,169	1,659,942,000	1,812,557,169	339,884	2,022,182	521,772	2,883,838	24
								25
1272 ACSR 36/1								26
1272 ACSR 45/7								27
795 ACSR 45/7								28
795 ACSR 26/7								29
1272 ACSR 36/1								30
795 ACSR 26/7								31
795 ACSR 26/7								32
954 ACSR 54/7								33
795 ACSR 26/7								34
1272 ACSR 36/1								35
	245,939,765	3,522,864,268	3,768,804,033	864,557	16,229,553	2,138,345	19,232,455	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 2018/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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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	BUFFALO, WY	CASPER, WY	230.00	230.00	Wood - H	107.00		1
2	CASPER, WY	DAVE JOHNSTON, WY	230.00	230.00	Wood - H	36.00		1
3	CASPER, WY	RIVERTON, WY	230.00	230.00	Wood - H	110.00		1
4	CHAPPEL CREEK, WY	CRAVEN CREEK, WY	230.00	230.00	Steel - SP	30.00		1
5	CHAPPEL CREEK, WY	JONAH GAS, WY	230.00	230.00	Wood - H	32.00		1
6	CHAPPEL CREEK, WY	RILEY RIDGE, WY	230.00	230.00	Wood - H	29.00	6.00	1
7	CRAVEN CREEK, WY	PIONEER, WY	230.00	230.00	Wood - H	2.00		1
8	DAVE JOHNSTON, WY	SPENCE, WY	230.00	230.00	Wood - H	31.00		1
9	DAVE JOHNSTON, WY	WYODAK, WY	230.00	230.00	Wood - H	69.00		1
10	DIXONVILLE 500kV, OR	DIXONVILLE 230kV, OR	230.00	230.00	Wood - H	1.00		1
11	DIXONVILLE, OR	RESTON (BPA), OR	230.00	230.00	Wood - H	17.00		1
12	FAIRVIEW (BPA), OR	ISTHMUS, OR	230.00	230.00	Wood - H	12.00		1
13	FIREHOLE, WY	MONUMENT, WY	230.00	230.00	Wood - H	49.00		1
14	FRY, OR	BETHEL, OR	230.00	230.00	Wood - H	26.00		1
15	FRY, OR	ALVEY, OR	230.00	230.00	Wood - H	45.00		1
16	GLEN CANYON, AZ	SIGURD, UT	230.00	230.00	Wood - H	159.00		1
17	GONDER, UT - NV STATE	PAVANT, UT	230.00	230.00	Wood - H	98.00		1
18	DIXONVILLE, OR	GRANTS PASS, OR	230.00	230.00	Wood - H	62.00		1
19	HIGH PLAINS, WY	STANDPIPE, WY	230.00	230.00	Wood - H	38.00		1
20	HURRICANE, OR	WALLA WALLA, WA	230.00	230.00	Wood - H	78.00		1
21	JIM BRIDGER, WY	ROCK SPRINGS, WY	230.00	230.00	Wood - H	35.00		1
22	JIM BRIDGER, WY	SPENCE, WY	230.00	230.00	Wood - H	149.00		1
23	KLAMATH FALLS, OR	MALIN, OR	230.00	230.00	Wood - H	36.00		1
24	LIMA, WY	ROBERSON, WY	230.00	230.00	Wood - H	2.00		1
25	LONE PINE, OR	KLAMATH FALLS, OR	230.00	230.00	Wood - H	76.00		1
26	LONE PINE, OR	MERIDIAN #1, OR	230.00	230.00	Steel - SP	5.00		1
27	LONE PINE, OR	MERIDIAN #2, OR	230.00	230.00	Steel - SP	5.00		1
28	MCNARY (BPA), WA	WALLA WALLA, WA	230.00	230.00	Wood - H	56.00		1
29	MERIDIAN, OR	GRANTS PASS, OR	230.00	230.00	Wood - H	35.00		1
30	MONUMENT, WY	EXXON, WY	230.00	230.00	Wood - H	13.00		1
31	MONUMENT, WY	CRAVEN CREEK, WY	230.00	230.00	Wood - H	20.00		1
32	NAUGHTON, WY	TREASURETON, ID	230.00	230.00	Wood - H	80.00		1
33	NAUGHTON, WY	MONUMENT, WY	230.00	230.00	Wood - H	30.00		1
34	NAUGHTON, WY	CRAVEN CREEK, WY	230.00	230.00	Wood - H	16.00		1
35	PALISADES SS, WY	BLUE RIM, WY	230.00	230.00	Wood - H	4.00		1
36					TOTAL	16,928.00	651.00	285

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TRANSMISSION LINE STATISTICS (Continued)

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1272 ACSR 36/1								1
								2
1272 ACSR 36/1								3
954 ACSR 54/7								4
1272 ACSR 45/7								5
1272 ACSR 45/7								6
1272 ACSR 45/7								7
1272 ACSR 45/7								8
1272 ACSR 36/1								9
1272 ACSR 36/1								10
795 ACSR 26/7								11
1272 ACSR 36/1								12
1272 ACSR 45/7								13
1272 ACSR 36/1								14
1272 ACSR 36/1								15
954 ACSR 45/7								16
795 ACSR 45/7								17
1272 ACSR 36/1								18
1272 ACSR 45/7								19
1272 ACSR 36/1								20
1272 ACSR 45/7								21
1272 ACSR 36/1								22
1272 ACSR 36/1								23
1272 ACSR 45/7								24
795 ACSR 26/7								25
1272 ACSR 54/19								26
1272 ACSR 36/1								27
1272 ACSR 36/1								28
1272 ACSR 36/1								29
1272 ACSR 36/1								30
1272 ACSR 45/7								31
1272 ACSR 45/7								32
1272 ACSR 36/1								33
954 ACSR 54/7								34
1272 ACSR 36/1								35
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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	PAROWAN VALLEY, UT	SIGURD, UT	230.00	230.00	Wood - H	94.00		1
2	PAROWAN VALLEY, UT	WEST CEDAR, UT	230.00	230.00	Wood - H	26.00		1
3	PAVANT, UT	SIGURD, UT	230.00	230.00	Wood - H	43.00		1
4	POINT OF ROCKS, WY	DAVE JOHNSTON, WY	230.00	230.00	Wood - H	209.00		1
5	POMONA, WA	UNION GAP, WA	230.00	230.00	Wood - H	7.00		1
6	RIVERTON, WY	ROCK SPRINGS, WY	230.00	230.00	Wood - H	118.00		1
7	RIVERTON, WY	THERMOPOLIS, WY	230.00	230.00	Wood - H	51.00		1
8	ROCK SPRINGS, WY	FLAMING GORGE, UT	230.00	230.00	Wood - H	55.00		1
9	ROCK SPRINGS, WY	JIM BRIDGER, WY	230.00	230.00	Wood - H	35.00		1
10	ROCK SPRINGS, WY	MONUMENT, WY	230.00	230.00	Wood - H	41.00		1
11	SHERIDAN (MDU), WY	BUFFALO, WY	230.00	230.00	Wood - H	40.00		1
12	SHERIDAN (MDU), WY	YELLOWTAIL, MT	230.00	230.00	Wood - H	62.00		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	230kV costs and expenses							
30	Subtotal 230kV					3,338.00	13.00	73
31								
32	ANTELOPE, ID	GOSHEN, ID	161.00	161.00	Wood - H	45.00		1
33	BIG GRASSY, ID	JEFFERSON, ID	161.00	161.00	Wood - H		21.00	1
34	BONNEVILLE, ID	EAGLEROCK, ID	161.00	161.00	Wood - SP	9.00		1
35	EAGLEROCK, ID	GOSHEN, ID	161.00	161.00	Wood - H	15.00		1
36					TOTAL	16,928.00	651.00	285

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.
795 ACSR 45/7								1
795 ACSR 45/7								2
795 ACSR 45/7								3
1272 ACSR 36/1								4
1272 ACSR 36/1								5
1272 ACSR 36/1								6
1272 ACSR 36/1								7
1272 ACSR 36/1								8
1272 ACSR 36/1								9
1272 ACSR 36/1								10
795 ACSR 26/7								11
795 ACSR 26/7								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
	19,999,280	399,993,714	419,992,994	82,576	2,482,173	389,978	2,954,727	29
	19,999,280	399,993,714	419,992,994	82,576	2,482,173	389,978	2,954,727	30
								31
397.5 ACSR 26/7								32
250HH CU /7								33
954 ACSR 45/7								34
1272 ACSR 45/7								35
	245,939,765	3,522,864,268	3,768,804,033	864,557	16,229,553	2,138,345	19,232,455	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 2018/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	GOSHEN, ID	GRACE, ID	161.00	161.00	Wood - H	57.00		1
2	GOSHEN, ID	JEFFERSON, ID	161.00	161.00	Wood - H		30.00	1
3	GOSHEN, ID	RIGBY, ID	161.00	161.00	Wood - H	31.00		1
4	GOSHEN, ID	SUGAR MILL, ID	161.00	161.00	Wood - SP	17.00		1
5	RIGBY, ID	JEFFERSON, ID	161.00	161.00	Wood - SP	18.00		1
6	SUGARMILL, ID	RIGBY, ID	161.00	161.00	Wood - SP	17.00		1
7	YELLOWTAIL, MT	RIMROCK, MT	161.00	161.00	Wood - H	46.00		1
8	161kV costs and expenses							
9	Subtotal 161kV					255.00	51.00	11
10								
11	90TH SOUTH, UT	DUMAS #1, UT	138.00	138.00	Wood - H	12.00		1
12	90TH SOUTH, UT	DUMAS #2, UT	138.00	138.00	Wood - H	6.00		1
13	90TH SOUTH, UT	OQUIRRH, UT	138.00	138.00	Wood - SP	10.00		1
14	90TH SOUTH, UT	SANDY, UT	138.00	138.00	Steel - SP	1.00		1
15	ABAJO, UT	PINTO, UT	138.00	138.00	Wood - H	44.00		1
16	ABAJO, UT	RESOLUTE, UT	138.00	138.00	Wood - SP	10.00		1
17	AGRIUM, UT	THREEMILE KNOLL, ID	138.00	138.00	Wood - H	4.00		1
18	ANSCHTZ CO-GEN, WY	EVANSTON, WY	138.00	138.00	Wood - H	22.00		1
19	ANTELOPE, ID	SCOVILLE #1, ID	138.00	138.00	Wood - H	1.00		1
20	ANTELOPE, ID	SCOVILLE #2, ID	138.00	138.00	Wood - H	1.00		1
21	ASHGROVE, UT	CLOVER, UT	138.00	138.00	Wood - H	26.00		1
22	ASHLEY, UT	CARBON, UT	138.00	138.00	Wood - H	102.00		1
23	ASHLEY, UT	VERNAL, UT	138.00	138.00	Wood - H	12.00		1
24	BANGERTER, UT	OQUIRRH, UT	138.00	138.00	Wood - H		6.00	1
25	BARNEYS, UT	GRINDING, UT	138.00	138.00	Wood - SP	1.00		1
26	BDO, UT	BDO TAP, UT	138.00	138.00	Wood - SP	1.00		1
27	BEN LOMOND, UT	ANGEL, UT	138.00	138.00	Steel - SP	27.00		1
28	BEN LOMOND, UT	BRIGHAM CITY, UT	138.00	138.00	Wood - H	14.00		1
29	BEN LOMOND #1, UT	EL MONTE, UT	138.00	138.00	Steel - SP	14.00		1
30	BEN LOMOND #2, UT	EL MONTE, UT	138.00	138.00			13.00	1
31	BEN LOMOND, UT	HONEYVILLE, UT	138.00	138.00	Steel Tower	22.00		1
32	BEN LOMOND, UT	SYRACUSE #1, UT	138.00	230.00	Steel Tower	7.00	13.00	1
33	BEN LOMOND, UT	SYRACUSE, UT	138.00	138.00	Steel Tower	58.00		1
34	BEN LOMOND, UT	W ZIRCONIUM, UT	138.00	138.00	Wood - SP	14.00		1
35	BEN LOMOND, UT	WHEELON, UT	138.00	138.00	Steel Tower	42.00		1
36					TOTAL	16,928.00	651.00	285

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.
250HH CU /7								1
250HH CU /7								2
397.5 ACSR 26/7								3
795 AAC /37								4
397.5 ACSR 26/7								5
397.5 ACSR 26/7								6
556.5 ACSR 26/7								7
	661,223	32,580,164	33,241,387	14,168	141,907	26,433	182,508	8
	661,223	32,580,164	33,241,387	14,168	141,907	26,433	182,508	9
								10
795 AAC /37								11
795 AAC /37								12
795 ACSR 26/7								13
795 AAC /37								14
397.5 ACSR 26/7								15
795 ACSR 26/7								16
397.5 ACSR 26/7								17
795 ACSR 26/7								18
397.5 ACSR 26/7								19
397.5 ACSR 26/7								20
397.5 ACSR 26/7								21
397.5 ACSR 26/7								22
397.5 ACSR 26/7								23
								24
1272 AAC /61								25
397.5 ACSR 26/7								26
397.5 ACSR 26/7								27
1272 ACSR 45/7								28
795 ACSR 45/7								29
795 ACSR 45/7								30
250 CUHD /12								31
795 AAC /37								32
1272 ACSR 45/7								33
795 AAC /37								34
250 CUHD /12								35
	245,939,765	3,522,864,268	3,768,804,033	864,557	16,229,553	2,138,345	19,232,455	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 2018/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 (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	BONANZA, UT	CHAPITA, UT	138.00	138.00	Wood - H	9.00		1
2	BRIDGERLAND, UT	GREEN CANYON, UT	138.00	138.00	Wood - SP	16.00		1
3	BRIGHAM CITY, UT	WHEELON, UT	138.00	138.00	Wood - H	24.00		1
4	BUTLERVILLE, UT	90TH SOUTH, UT	138.00	138.00	Steel - SP	9.00		1
5	CAMERON, UT	MILFORD, UT	138.00	138.00	Wood - SP	25.00		1
6	CAMERON, UT	PAROWAN, UT	138.00	138.00	Wood - H	35.00		1
7	CAMERON, UT	SIGURD, UT	138.00	138.00	Wood - H	65.00		1
8	CANYON COMP, WY	STR 204, WY	138.00	138.00	Wood - H	12.00		1
9	CARBON, UT	HELPER #2, UT	138.00	138.00	Wood - H	2.00		1
10	CARBON, UT	MOAB, UT	138.00	138.00	Wood - H	120.00		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	CENTRAL (UAMPS) #2, UT	SAINT GEORGE, UT	138.00	138.00	Steel - SP	20.00		1
14	CENTRAL (UAMPS) #3, UT	SAINT GEORGE, UT	138.00	138.00	Steel - SP		20.00	1
15	CLEAR CREEK, WY	PAINTER, UT	138.00	138.00	Wood - SP	5.00		1
16	CLOVER, UT	BURRASTON PONDS	138.00	138.00	Wood - SP	2.00		1
17	CLOVER, UT	NEBO, UT	138.00	138.00	Wood - SP	8.00		1
18	COLUMBIA, UT	SUNNYSIDE, UT	138.00	138.00	Wood - H	2.00		1
19	COTTONWOOD, UT	HAMMER, UT	138.00	138.00	Wood - SP	5.00		1
20	COTTONWOOD, UT	MCCLELLAND, UT	138.00	138.00	Steel - SP	6.00		1
21	COTTONWOOD, UT	SILVER CREEK, UT	138.00	138.00	Wood - SP	30.00		1
22	CUTLER, UT	WHEELON, UT	138.00	138.00	Wood - SP			1
23	DRY CREEK, UT	SPANISH FORK, UT	138.00	138.00	Steel - SP	5.00		1
24	DUMAS, UT	WESTFIELD, UT	138.00	138.00	Wood - SP	19.00		1
25	DYNAMO, UT	TRI-CITY #1, UT	138.00	138.00	Steel - SP	2.00		1
26	DYNAMO, UT	TRI-CITY #2, UT	138.00	138.00			3.00	1
27	EAGLE MOUNTAIN, UT	PONY EXPRESS, UT	138.00	138.00	Wood - SP	10.00		1
28	EAST LAYTON, UT	105 TAP, UT	138.00	138.00	Steel - SP	15.00		1
29	EBAY TAP, UT	OQUIRRH, UT	138.00	138.00	Wood - SP	1.00		1
30	EL MONTE, UT	PIONEER, UT	138.00	138.00	Steel - SP	1.00		1
31	EL MONTE, UT	EAST BANK, UT	138.00	138.00	Steel - SP	4.00		1
32	EVANSTON, WY	RAILROAD, UT	138.00	138.00	Wood - SP	3.00		1
33	FORT DOUGLAS, UT	MCCLELLAND, UT	138.00	138.00	Wood - SP	3.00		1
34	FRANKLIN, ID	GREEN CANYON, UT	138.00	138.00	Wood - SP	25.00		1
35	FRANKLIN, ID	TREASURETON, ID	138.00	138.00	Wood - SP	10.00		1
36					TOTAL	16,928.00	651.00	285

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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795 ACSR 26/7								1
1272 ACSR 45/7								2
795 ACSR 26/7								3
795 AAC /37								4
397.5 ACSR 26/7								5
397.5 ACSR 26/7								6
397.5 ACSR 26/7								7
795 ACSR 26/7								8
556.5 ACSR 26/7								9
954 ACSR 54/7								10
795 ACSR 26/7								11
1272 ACSR 45/7								12
1272 ACSR 45/7								13
1272 ACSR 45/7								14
795 ACSR 26/7								15
397.5 ACSR 26/7								16
1272 ACSR 45/7								17
397.5 ACSR 26/7								18
795 AAC /37								19
795 AAC /37								20
397.5 ACSR 26/7								21
250 CUHD /12								22
1272 ACSR 45/7								23
795 ACSR 26/7								24
795 ACSR 26/7								25
795 ACSR 26/7								26
795 ACSR 26/7								27
795 ACSR 26/7								28
795 ACSR 26/7								29
1272 ACSR 45/7								30
1272 ACSR 45/7								31
795 ACSR 26/7								32
								33
397.5 ACSR 26/7								34
795 ACSR 26/7								35
	245,939,765	3,522,864,268	3,768,804,033	864,557	16,229,553	2,138,345	19,232,455	36

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	GADSBY, UT	JORDAN, UT	138.00	138.00	Wood - SP			1
2	GADSBY, UT	TERMINAL, UT	138.00	138.00	Wood - SP	6.00		1
3	GADSBY, UT	THIRD WEST, UT	138.00	138.00	Wood - SP	1.00		1
4	GRAPHITE, UT	MOUNTAIN VIEW, UT	138.00	138.00	Wood - SP	1.00		1
5	GREEN CANYON, UT	NIBLEY, UT	138.00	138.00	Wood - SP	7.00		1
6	GREEN CANYON, UT	WHEELON, UT	138.00	138.00	Wood - SP	19.00		1
7	GRINDING, UT	OQUIRRH, UT	138.00	138.00	Wood - SP	3.00		1
8	GRINDING, UT	TOOELE, UT	138.00	138.00	Wood - SP	14.00		1
9	HALE, UT	MIDWAY, UT	138.00	138.00	Wood - H	19.00		1
10	HALE, UT	SPANISH FORK, UT	138.00	138.00	Wood - H	18.00		1
11	HALE, UT	TANNER, UT	138.00	138.00	Wood - H	7.00		1
12	HAMMER, UT	BUTLERVILLE, UT	138.00	138.00			2.00	1
13	HIGHLAND, UT	BULL RIVER (LEHI #5), UT	138.00	138.00	Wood - SP	5.00		1
14	HONEYVILLE, UT	LAMPO, UT	138.00	138.00	Wood - H	25.00		1
15	HONEYVILLE, UT	WHEELON, UT	138.00	138.00			14.00	1
16	HUNTINGTON, UT	MCFADDEN, UT	138.00	138.00	Wood - H	7.00		1
17	JERUSALEM, UT	NEBO, UT	138.00	138.00	Wood - H	26.00		1
18	JORDAN, UT	MCCLELLAND, UT	138.00	138.00	Wood - SP	5.00		1
19	JORDAN, UT	TERMINAL, UT	138.00	138.00	Wood - SP	6.00		1
20	JORDAN, UT	THIRD WEST, UT	138.00	138.00	Wood - SP	1.00		1
21	KEARNS, UT	TAYLORSVILLE, UT	138.00	138.00	Wood - SP	3.00		1
22	KEARNS, UT	WEST VALLEY, UT	138.00	138.00	Wood - SP	2.00		1
23	LONE PEAK, UT	CAMP WILLIAMS, UT	138.00	138.00			8.00	1
24	MCCLELLAND, UT	MIDVALLEY, UT	138.00	138.00	Wood - SP	6.00		1
25	MCFADDEN, UT	BLACKHAWK, UT	138.00	138.00	Wood - H	11.00		1
26	MID VALLEY, UT	90TH SOUTH, UT	138.00	138.00	Wood - H	9.00		1
27	MID VALLEY #2, UT	COTTONWOOD, UT	138.00	138.00	Wood - SP	3.00		1
28	MID VALLEY #1, UT	COTTONWOOD, UT	138.00	138.00	Wood - SP	5.00		1
29	MID VALLEY, UT	TAYLORSVILLE, UT	138.00	138.00	Wood - SP	4.00	2.00	1
30	MIDDLETON, UT	ST GEORGE, UT	138.00	138.00	Wood - H			1
31	MOAB, UT	PINTO, UT	138.00	138.00	Wood - H	68.00		1
32	NAUGHTON, WY	CANYON COMP, WY	138.00	138.00	Wood - H	35.00		1
33	NAUGHTON, WY	PAINTER, WY	138.00	138.00	Wood - H	44.00		1
34	NEBO, UT	DRY CREEK, UT	138.00	138.00	Wood - H	33.00		1
35	NUCOR STEEL, UT	WHEELON, UT	138.00	138.00	Wood - H	10.00		1
36					TOTAL	16,928.00	651.00	285

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1272 ACSR 45/7								1
1272 ACSR 45/7								2
1272 AAC /61								3
397.5 ACSR 26/7								4
1272 ACSR 45/7								5
397.5 ACSR 26/7								6
795 ACSR 45/7								7
795 ACSR 45/7								8
397.5 ACSR 26/7								9
1272 ACSR 45/7								10
1272 ACSR 45/7								11
795 ACSR 26/7								12
1272 ACSR 45/7								13
397.5 ACSR 26/7								14
250 CUHD /12								15
397.5 ACSR 26/7								16
397.5 ACSR 26/7								17
795 AAC /37								18
1272 AAC/91								19
1272 AAC /61								20
795 ACSR 26/7								21
								22
1272 ACSR 45/7								23
795 AAC 26/7								24
795 AAC 26/7								25
1272 ACSR 45/7								26
								27
								28
1272 ACSR /61								29
397.5 ACSR 26/7								30
397.5 ACSR 26/7								31
795 AAC 26/7								32
795 AAC 26/7								33
795 AAC 26/7								34
397.5 ACSR 26/7								35
	245,939,765	3,522,864,268	3,768,804,033	864,557	16,229,553	2,138,345	19,232,455	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 2018/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	ONEIDA, ID	OVID, UT	138.00	138.00	Wood - H	23.00		1
2	ONIEDA, ID	GRACE, ID	138.00	138.00	Wood - H	19.00		1
3	OQUIRRH, UT	BARNEY, UT	138.00	138.00	Wood - H	5.00		1
4	OQUIRRH, UT	BINGHAM CANYON, UT	138.00	138.00	Wood - H	8.00		1
5	OQUIRRH, UT	TOOELE, UT	138.00	138.00	Steel - SP	23.00		1
6	PAINTER, UT	RAILROAD, UT	138.00	138.00	Wood - H	7.00		1
7	PARRISH #105, UT	TERMINAL, UT	138.00	138.00	Steel - SP	14.00		1
8	PAROWAN, UT	WEST CEDAR, UT	138.00	138.00	Wood - H	21.00		1
9	PARRISH, UT	TAP TO N. SALT LAKE, UT	138.00	138.00	Steel - SP		8.00	1
10	PARRISH, UT	TERMINAL #1, UT	138.00	138.00	Steel - SP	16.00		1
11	PARRISH, UT	TERMINAL #2, UT	138.00	138.00			14.00	1
12	RAILROAD, UT	CANYON COMP, WY	138.00	138.00	Wood - H	17.00		1
13	RED BUTTE, UT	PURGATORY FLAT, UT	138.00	138.00	Wood - SP	11.00		1
14	RED BUTTE, UT	WEST CEDAR, UT	138.00	138.00	Wood - H	49.00		1
15	RIVERDALE, UT	EAST LAYTON, UT	138.00	138.00	Steel - SP		7.00	1
16	SHICK, UT	PARRISH, UT	138.00	138.00	Wood - H		10.00	1
17	SILVER CREEK, UT	JORDANELLE, UT	138.00	138.00	Wood - SP	10.00		1
18	SILVER CREEK, UT	RAILROAD, UT	138.00	138.00	Wood - SP	72.00		1
19	SPANISH FORK, UT	TANNER, UT	138.00	138.00	Wood - H	10.00		1
20	SUNRISE, UT	OQUIRRH, UT	138.00	138.00	Wood - SP		2.00	1
21	SYRACUSE, UT	ANGEL #1, UT	138.00	138.00			7.00	1
22	SYRACUSE, UT	CLEARFIELD SOUTH, UT	138.00	138.00	Steel - SP	5.00		1
23	SYRACUSE, UT	PARRISH, UT	138.00	138.00	Steel Tower	15.00		1
24	TAP TO ANGEL NORTH, UT	TAP TO PARRISH, UT	138.00	138.00	Wood - H	4.00		1
25	TAYLORSVILLE, UT	90TH SOUTH, UT	138.00	138.00	Wood - SP	6.00	2.00	1
26	TERMINAL, UT	KENNECOTT, UT	138.00	138.00	Steel - SP	9.00		1
27	TERMINAL, UT	MIDVALLEY #1, UT	138.00	138.00	Wood - H	7.00		1
28	TERMINAL, UT	MIDVALLEY #2, UT	138.00	138.00	Wood - H	7.00		1
29	TERMINAL, UT	ROWLEY, UT	138.00	138.00	Wood - H	53.00		1
30	TERMINAL, UT	TOOELE, UT	138.00	138.00	Wood - H	24.00	6.00	1
31	TERMINAL, UT	WEST VALLEY, UT	138.00	138.00	Wood - SP	7.00		1
32	THREEMILE KNOLL, ID	GRACE #1, ID	138.00	138.00	Wood - H	17.00		1
33	THREEMILE KNOLL, ID	GRACE #2, ID	138.00	138.00	Wood - H	17.00		1
34	THREEMILE KNOLL, ID	MONSANTO #1, ID	138.00	138.00	Wood - H	2.00		1
35	THREEMILE KNOLL, ID	MONSANTO #2, ID	138.00	138.00	Steel - SP	2.00		1
36					TOTAL	16,928.00	651.00	285

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 2018/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.
336.4 ACSR 26/7								1
250 CUHD /12								2
795 AAC 26/7								3
								4
1272 ACSR 45/7								5
1272 ACSR 45/7								6
795 AAC 45/7								7
397.5 ACSR 26/7								8
795 AAC 26/7								9
795 AAC 45/7								10
795 AAC 26/7								11
795 ACSR 26/7								12
1272 ACSR 45/7								13
397.5 ACSR 26/7								14
795 AAC 26/7								15
250 CUHD /12								16
795 AAC 26/7								17
1272 ACSR 45/7								18
1272 ACSR 45/7								19
								20
250 CUHD /12								21
1272 ACSR 45/7								22
1272 ACSR 45/7								23
795 AAC /37								24
795 AAC /37								25
795 AAC 26/7								26
1272 ACSR 45/7								27
1272 AAC /61								28
795 AAC /37								29
397.5 ACSR 26/7								30
								31
250 CUHD /12								32
1272 ACSR 45/7								33
1272 AAC /61								34
1272 ACSR 45/7								35
	245,939,765	3,522,864,268	3,768,804,033	864,557	16,229,553	2,138,345	19,232,455	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 2018/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	TIMP #1, UT	DYNAMO, UT	138.00	138.00	Steel - SP	2.00		1
2	TIMP #2, UT	DYNAMO, UT	138.00	138.00			2.00	1
3	TIMP, UT	HALE, UT	138.00	138.00	Steel - SP	4.00		1
4	TIMP, UT	SPANISH FORK, UT	138.00	138.00	Wood - H	20.00		1
5	TIMP, UT	VINEYARD, UT	138.00	138.00	Wood - SP	2.00		1
6	TREASURETON, ID	GRACE, ID	138.00	138.00	Steel Tower	25.00		1
7	TREASURETON, ID	GRACE #2, ID	138.00	138.00			25.00	1
8	TREASURETON, ID	ONEIDA, ID	138.00	138.00	Wood - H	6.00		1
9	TRI-CITY, UT	BANGERTER, UT	138.00	138.00	Wood - SP	6.00	12.00	1
10	TRI-CITY, UT	SUNRISE, ID	138.00	138.00	Wood - SP	22.00		1
11	TRI-CITY, UT	WESTFIELD, UT	138.00	138.00	Wood - H	15.00		1
12	WEST CEDAR, UT	THREE PEAKS, UT	138.00	138.00	Wood - SP	20.00		1
13	WEST VALLEY, UT	OQUIRRH, UT	138.00	138.00	Wood - H	9.00		1
14	WESTFIELD, UT	HALE, UT	138.00	138.00	Wood - H	13.00		1
15	WHEELON, UT	AMERICAN FALLS, ID	138.00	138.00	Wood - H	87.00		1
16	WHEELON #1, UT	TREASURETON, ID	138.00	138.00	Steel Tower	29.00		1
17	WHEELON #2, UT	TREASURETON, ID	138.00	138.00			29.00	1
18	WHEELON #3, UT	TREASURETON, ID	138.00	138.00	Wood - H	29.00		1
19	138kV costs and expenses							
20	Subtotal 138kV					2,222.00	205.00	148
21								
22	All 115kV Lines					1,655.00		
23								
24	All 69kV Lines					2,913.00		
25								
26	All 57kV Lines					107.00		
27								
28	All 46kV Lines					2,473.00		
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	16,928.00	651.00	285

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 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
								2
								3
								4
1272 ACSR 45/7								5
250 CUHD /12								6
250 CUHD /12								7
250 CUHD /12								8
								9
								10
1272 ACSR 45/7								11
795 AAC 26/7								12
								13
795 AAC 26/7								14
250 CUHD /12								15
250 CUHD /12								16
250 CUHD /12								17
250 CUHD /12								18
	33,900,036	408,031,032	441,931,068	242,614	1,784,831	165,019	2,192,464	19
	33,900,036	408,031,032	441,931,068	242,614	1,784,831	165,019	2,192,464	20
								21
	5,427,950	203,209,263	208,637,213	35,385	2,560,171	460,910	3,056,466	22
								23
	8,352,584	291,850,158	300,202,742	43,358	3,490,634	170,890	3,704,882	24
								25
	52,655	12,435,120	12,487,775	1,516	30,951	6,034	38,501	26
								27
	11,591,169	277,697,935	289,289,104	104,607	2,253,138	66,642	2,424,387	28
								29
								30
								31
								32
								33
								34
								35
	245,939,765	3,522,864,268	3,768,804,033	864,557	16,229,553	2,138,345	19,232,455	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 328-330, Transmission of electricity for others, in this Form No. 1.

Schedule Page: 422 Line No.: 2 Column: a

The Alvey - Dixonville 500kV line is jointly owned by PacifiCorp and Bonneville Power Administration ("BPA"), each with an undivided interest of 50.0%. Plant cost reported for this line represents 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.: 4 Column: a

The Dixonville - Meridian 500kV line is jointly owned by PacifiCorp and BPA, each with an undivided interest of 50.0%. Plant cost reported for this line represents 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.: 8 Column: a

The Midpoint - Malin 500kV line is jointly owned by PacifiCorp and Idaho Power Company. Ownership of the line designation 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 represents PacifiCorp’s share.

Schedule Page: 422 Line No.: 9 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, in which PacifiCorp owns 6.8% of the line. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp’s share.

Schedule Page: 422 Line No.: 10 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, in which PacifiCorp owns 6.8% of the line. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp's share.

Schedule Page: 422 Line No.: 11 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, in which PacifiCorp owns 6.8% of the line. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp's share.

Schedule Page: 422 Line No.: 12 Column: a

The Broadview - Townsend A 500kV line is jointly owned by PacifiCorp, NorthWestern Corporation, Puget Sound Energy, Avista Corporation and Portland General Electric Company, in which PacifiCorp owns 8.1% of the line. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp's share.

Schedule Page: 422 Line No.: 13 Column: a

The Broadview - Townsend B 500kV line is jointly owned by PacifiCorp, NorthWestern Corporation, Puget Sound Energy, Avista Corporation and Portland General Electric Company, in which PacifiCorp owns 8.1% of the line. Plant cost and operation and maintenance costs reported for this line represents 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 Line No.: 26 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 represents PacifiCorp’s share.

Schedule Page: 422 Line No.: 27 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 represents PacifiCorp’s share.

Schedule Page: 422.1 Line No.: 4 Column: a

The Goshen - Kinport 345kV line is jointly owned by PacifiCorp and Idaho Power Company with an undivided interest of 81.7% and 18.3%, respectively. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp’s share.

Schedule Page: 422.1 Line No.: 9 Column: a

The Jim Bridger - Goshen 345kV line is jointly owned by PacifiCorp and Idaho Power Company with an undivided interest of 70.8% and 29.2%, respectively. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp’s share.

Schedule Page: 422.1 Line No.: 10 Column: a

The Jim Bridger - Borah 345kV line is jointly owned by PacifiCorp and Idaho Power Company. Ownership of the line designation 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 represents PacifiCorp’s share.

Schedule Page: 422.1 Line No.: 11 Column: a

The Jim Bridger - Kinport 345kV line is jointly owned by PacifiCorp and Idaho Power Company. Ownership of the line designation 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 represents PacifiCorp’s share.

Schedule Page: 422.1 Line No.: 12 Column: a

The Kinport - Midpoint 345kV line is jointly owned by PacifiCorp and Idaho Power Company with an undivided interest of 26.8% and 73.2%, respectively. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp’s share.

Schedule Page: 422.2 Line No.: 2 Column: a

A 1.5 mile segment of the Casper - Dave Johnston 230kV line is jointly owned by PacifiCorp and Black Hills Power with an undivided interest of 43.75% and 56.25%, respectively. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp's share.

Schedule Page: 422.2 Line No.: 2 Column: i

1557 ACSS/TW 45/7

Schedule Page: 422.2 Line No.: 17 Column: a

Complete name is Gonder (NV Energy), UT - NV State

Schedule Page: 422.2 Line No.: 20 Column: a

The Hurricane - Walla Walla 230kV line is jointly owned by PacifiCorp and Idaho Power Company with an undivided interest of 59.2% and 40.8%, respectively. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp’s share.

Schedule Page: 422.3 Line No.: 32 Column: a

The Antelope - Goshen 161kV line is jointly owned by PacifiCorp and Idaho Power Company with an undivided interest of 78.1% and 21.9%, respectively. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp’s share.

Schedule Page: 422.3 Line No.: 33 Column: a

The Big Grassy - Jefferson 161kV line is jointly owned by PacifiCorp and Idaho Power company with an undivided interest of 62.2% and 37.8%, respectively. Plant costs and operation and maintenance costs reported for this line represents PacifiCorp's share.

Schedule Page: 422.4 Line No.: 2 Column: a

The Goshen - Jefferson 161kV line is jointly owned by PacifiCorp and Idaho Power Company with an undivided interest of 62.2% and 37.8%, respectively. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp’s share.

Schedule Page: 422.4 Line No.: 19 Column: a

The Antelope - Scoville #1 138kV line is jointly owned by PacifiCorp and Idaho Power Company with an undivided interest of 33.3% and 66.7%, respectively. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp’s share.

Schedule Page: 422.4 Line No.: 20 Column: a

The Antelope - Scoville #2 138kV line is jointly owned by PacifiCorp and Idaho Power Company with an undivided interest of 33.3% and 66.7%, respectively. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp’s share.

Schedule Page: 422.4 Line No.: 24 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.5 Line No.: 13 Column: a

The Central - St. George 138kV line is jointly owned by PacifiCorp and Utah Associated Municipal Power Systems with an undivided interest of 43.26% and 56.74%, respectively. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp's share.

Schedule Page: 422.5 Line No.: 14 Column: a

The Central - St. George 138kV line is jointly owned by PacifiCorp and Utah Associated Municipal Power Systems with an undivided interest of 43.26% and 56.74%, respectively. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp's share.

Schedule Page: 422.5 Line No.: 16 Column: b

Complete name is Burraston Ponds Metering, UT

Schedule Page: 422.5 Line No.: 33 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 22 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 27 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 28 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 4 Column: b

Complete name is Bingham Canyon (KCC), UT

Schedule Page: 422.7 Line No.: 4 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 20 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 31 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 1 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 2 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 3 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 4 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.: 10 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 13 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 15 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 represents PacifiCorp’s share.

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 2018/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	ST GEORGE, UT	PURGATORY FLAT, UT	10.00	Wood - SP	8.00	2	2
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		10.00		8.00	2	2

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
1272	ACSR	Vertical 10'	138	676,370	574,876	423,866	-158,811	1,516,301	1
									2
									3
									4
									5
									6
									7
									8
									9
									10
									11
									12
									13
									14
									15
									16
									17
									18
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									21
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									36
									37
									38
									39
									40
									41
									42
									43
				676,370	574,876	423,866	-158,811	1,516,301	44

Schedule Page: 424 Line No.: 1 Column: a

Lines added to the designation from Red Butte, Utah to Purgatory Flat, Utah

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 2018/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	CALIFORNIA				
2	BELMONT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	BIG SPRINGS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	CASTELLA SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
5	CLEAR LAKE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	DOG CREEK SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
7	DORRIS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	FORT JONES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	GASQUET SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
10	GREENHORN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
11	HAMBURG SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
12	HAPPY CAMP SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	HORNBROOK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	INTERNATIONAL PAPER SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
15	LAKE EARL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	LITTLE SHASTA SUB	DISTRIBUTION-UNATTEN	69.00	7.20	
17	LUCERNE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
18	MACDOEL SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
19	MCCLOUD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	MILLER REDWOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	MONTAGUE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	MORRISON CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.50	
23	MOUNT SHASTA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	NEWELL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	NORTH DUNSMUIR SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	NORTHCREST SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	NUTGLADE SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
28	PATRICKS CREEK SUB	DISTRIBUTION-UNATTEN	115.00	7.20	
29	PEREZ SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	REDWOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	SCOTT BAR SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	SEIAD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	SHASTINA SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
34	SHOTGUN CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	SMITH RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	SNOW BRUSH SUB	DISTRIBUTION-UNATTEN	69.00	7.20	
37	SOUTH DUNSMUIR SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
38	TULELAKE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	TUNNEL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	WALKER BRYAN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
						1
25	1					2
6	1					3
1	3					4
4	3					5
	1					6
7	3					7
6	1					8
9	1					9
12	1					10
1	1					11
7	3					12
4	3					13
9	3					14
12	1					15
2	3					16
4	1					17
30	2					18
6	1					19
4	3					20
6	1					21
14	1					22
16	4					23
12	1					24
6	6					25
20	4					26
1	3					27
1	1					28
1	3					29
9	3					30
2	3					31
2	3					32
6	3					33
1	1					34
6	3					35
1	3					36
2	3					37
20	1					38
6	6					39
9	3					40

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WEED SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
2	YUBA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	YUROK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	TOTAL (Number of Substations-42)		3082.00	465.96	
5					
6	ALTURAS SUB	T/D-UNATTENDED	115.00	69.00	
7	YREKA SUB	T/D-UNATTENDED	115.00	12.47	69.00
8	TOTAL (Number of Substations-2)		230.00	81.47	69.00
9					
10	COPCO #2 230 SUB	TRANSMISSION-ATTENDE	230.00	115.00	
11	COPCO #2 SUB	TRANSMISSION-ATTENDE	115.00	69.00	12.47
12	AGER SUB	TRANSMISSION-UNATTEN	115.00	69.00	
13	CRAG VIEW SUB	TRANSMISSION-UNATTEN	115.00	69.00	
14	DEL NORTE SUB	TRANSMISSION-UNATTEN	115.00	69.00	
15	TOTAL (Number of Substations-5)		690.00	391.00	12.47
16					
17	IDAHO				
18	ALEXANDER	DISTRIBUTION-UNATTEN	46.00	12.47	
19	AMMON	DISTRIBUTION-UNATTEN	69.00	12.47	
20	ANDERSON	DISTRIBUTION-UNATTEN	69.00	12.47	
21	ARCO	DISTRIBUTION-UNATTEN	69.00	12.47	
22	ARIMO	DISTRIBUTION-UNATTEN	46.00	12.47	
23	BANCROFT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	BELSON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	BERENICE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	CAMAS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	CANYON CREEK SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
28	CHESTERFIELD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	CLEMENTS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	CLIFTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	COVE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	DOWNEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	DUBOIS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	EASTMONT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	EGIN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	EIGHT MILE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	GEORGETOWN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	GRACE CITY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	HAMER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	HAYES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
25	1					1
4	3					2
4	3					3
323	99					4
						5
35	4					6
95	2					7
130	6					8
						9
500	2					10
51	4					11
5	3					12
19	3					13
150	2					14
725	14					15
						16
						17
4	1					18
14	1					19
20	1					20
6	1					21
7	1					22
4	1					23
12	1					24
10	1					25
14	1					26
20	1					27
5	1					28
5	1					29
4	1					30
6	1					31
5	1					32
12	1					33
14	1					34
14	1					35
4	1					36
6	1					37
5	1					38
14	1					39
9	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 2018/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	HENRY SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
2	HOLBROOK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	HOOPES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	HORSLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	IDAHO FALLS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	INDIAN CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	JEFFCO SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
8	KETTLE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
9	LAVA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	LUND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	MCCAMMON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	MENAN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	MERRILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	MILLER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
15	MONTPELIER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	MOODY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
17	NEWDALE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	OSGOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	PRESTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	RAYMOND SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	RENO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	REXBURG SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	RIRIE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	ROBERTS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	RUBY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	SAND CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	SANDUNE SUB	DISTRIBUTION-UNATTEN	67.00	24.90	
28	SHELLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	SMITH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	SOUTH FORK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	SPUD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	ST. CHARLES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	SUGAR CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	SUNNYDELL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	TANNER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	TARGHEE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	THORNTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	UCON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	WATKINS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	WEBSTER 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)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Total Capacity (In MVa) (k)	Line No.
1	1					1
6	1					2
9	1					3
4	1					4
20	1					5
3	1					6
22	1					7
14	1					8
6	1					9
5	1					10
3	1					11
10	1					12
20	1					13
5	1					14
8	1					15
14	1					16
20	1					17
20	1					18
12	1					19
2	1					20
20	1					21
32	2					22
9	1					23
8	1					24
7	1					25
40	2					26
30	1					27
20	1					28
20	1					29
14	1					30
8	1					31
5	1					32
12	1					33
13	1					34
4	1					35
4	1					36
7	1					37
7	1					38
14	1					39
20	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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	WESTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	WINDSPER SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
3	TOTAL (Number of Substations-65)		4000.00	867.43	
4					
5	CINDER BUTTE SUB	T/D-UNATTENDED	161.00	12.47	
6	MALAD SUB	T/D-UNATTENDED	138.00	69.00	12.47
7	MUD LAKE SUB	T/D-UNATTENDED	69.00	12.47	
8	RIGBY SUB	T/D-UNATTENDED	161.00	12.47	69.00
9	SAINT ANTHONY SUB	T/D-UNATTENDED	69.00	46.00	12.47
10	TOTAL (Number of Substations-5)		598.00	152.41	93.94
11					
12	AMPS SUB	TRANSMISSION-UNATTEN	230.00	69.00	12.47
13	ANTELOPE SUB	TRANSMISSION-UNATTEN	230.00	161.00	13.80
14	ASHTON PLANT	TRANSMISSION-UNATTEN	46.00	12.47	2.40
15	BIG GRASSY SUB	TRANSMISSION-UNATTEN	161.00	69.00	
16	BONNEVILLE SUB	TRANSMISSION-UNATTEN	161.00	69.00	
17	CONDA SUB	TRANSMISSION-UNATTEN	138.00	46.00	
18	FISH CREEK SUB	TRANSMISSION-UNATTEN	161.00	46.00	
19	FRANKLIN SUB	TRANSMISSION-UNATTEN	138.00	46.00	
20	GOSHEN SUB	TRANSMISSION-UNATTEN	345.00	161.00	69.00
21	GRACE SUB	TRANSMISSION-UNATTEN	161.00	138.00	12.50
22	JEFFERSON SUB	TRANSMISSION-UNATTEN	161.00	69.00	
23	MIDPOINT SUB	TRANSMISSION-UNATTEN	500.00	345.00	
24	OVID SUB	TRANSMISSION-UNATTEN	138.00	69.00	
25	SCOVILLE SUB	TRANSMISSION-UNATTEN	138.00	69.00	
26	SUGARMILL SUB	TRANSMISSION-UNATTEN	161.00	46.00	69.00
27	THREEMILE KNOLL SUB	TRANSMISSION-UNATTEN	345.00	138.00	46.00
28	TREASURETON SUB	TRANSMISSION-UNATTEN	230.00	138.00	
29	WESTWOOD SUB	TRANSMISSION-UNATTEN	161.00	13.20	
30	TOTAL (Number of Substations-18)		3605.00	1704.67	225.17
31					
32	MONTANA				
33	BROADVIEW SUB	TRANSMISSION-UNATTEN	500.00	230.00	
34	COLSTRIP SUB	TRANSMISSION-UNATTEN	500.00	230.00	
35	YELLOWTAIL SUB	TRANSMISSION-UNATTEN	230.00	161.00	
36	TOTAL (Number of Substations-3)		1230.00	621.00	
37					
38	OREGON				
39	26TH STREET	DISTRIBUTION-UNATTEN	20.80	4.16	
40	35TH STREET	DISTRIBUTION-UNATTEN	20.80	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 2018/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
20	1					2
736	67					3
						4
30	1					5
39	4	1				6
14	1					7
189	4					8
40	2					9
312	12	1				10
						11
75	1					12
250	1					13
15	1					14
67	1					15
67	1					16
67	1					17
25	3					18
75	1					19
908	4	1				20
217	2					21
233	3					22
1500	1	1				23
30	1					24
76	2					25
168	3					26
775	2					27
533	2					28
30	1					29
5111	31	2				30
						31
						32
32	2					33
68	2					34
100	1					35
200	5					36
						37
						38
5	1					39
30	6					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 2018/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	AGNESS AVE	DISTRIBUTION-UNATTEN	115.00	12.47	
2	ALDERWOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	ARLINGTON	DISTRIBUTION-UNATTEN	69.00	12.47	
4	ATHENA	DISTRIBUTION-UNATTEN	69.00	12.47	
5	BANDON TIE SUB	DISTRIBUTION-UNATTEN	20.80	12.47	
6	BEACON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	BEALL LANE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
8	BEATTY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	BELKNAP SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
10	BLALOCK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
11	BLOSS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
12	BLY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	BOISE CASCADE SUB	DISTRIBUTION-UNATTEN	69.00	11.00	
14	BONANZA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
15	BOND STREET SUB	DISTRIBUTION-UNATTEN	69.00	12.50	
16	BROOKHURST SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
17	BROWNSVILLE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
18	BRYANT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	BUCHANAN SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
20	BUCKAROO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	CAMPBELL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
22	CANNON BEACH SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
23	CANYONVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
24	CARNES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	CASEBEER SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
26	CAVEMAN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
27	CHERRY LANE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
28	CHILOQUIN MARKET SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
29	CHINA HAT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	CIRCLE BLVD SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
31	CLEVELAND AVE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	CLOAKE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
33	COBURG SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
34	COLISEUM SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
35	COLUMBIA SUB	DISTRIBUTION-UNATTEN	115.00	69.00	12.47
36	COOS RIVER SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
37	COQUILLE SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
38	CREEK SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
39	CROOKED RIVER RANCH SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
40	CROWFOOT SUB	DISTRIBUTION-UNATTEN	115.00	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 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
25	1					1
45	2					2
5	1					3
9	1					4
8	3	1				5
11	3					6
25	1					7
6	1					8
40	2					9
2	3					10
32	2					11
8	3					12
3	1					13
8	3					14
25	1					15
50	2					16
13	1					17
40	2					18
45	2					19
34	2					20
20	2					21
13	1					22
25	1					23
9	3					24
20	1					25
45	2					26
25	1					27
9	3					28
25	1					29
80	2					30
45	2					31
20	1					32
10	3					33
9	2					34
128	4	1				35
20	1					36
40	2					37
5	1					38
25	2					39
20	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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	CULLY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
2	CULVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	DAIRY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	DALLAS SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
5	DALREED SUB	DISTRIBUTION-UNATTEN	230.00	34.40	
6	DEVILS LAKE SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
7	DIXON SUB	DISTRIBUTION-UNATTEN	115.00	4.16	
8	DODGE BRIDGE SUB	DISTRIBUTION-UNATTEN	70.60	20.80	
9	DOWELL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
10	EASY VALLEY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
11	EMPIRE SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
12	ENTERPRISE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	FERN HILL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
14	FIELDER CREEK SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
15	FOOTHILLS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	FRALEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
17	GARDEN VALLEY SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
18	GLENDALE SUB	DISTRIBUTION-UNATTEN	230.00	12.47	
19	GLENEDEN SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
20	GLIDE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
21	GOLD HILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	GORDON HOLLOW SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	GOSHEN SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
24	GRANT STREET SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
25	GREEN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	GRIFFIN CREEK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
27	HAMAKER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
28	HARRISBURG SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
29	HENLEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	HERMISTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	HILLVIEW SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
32	HINKLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	HOLLADAY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
34	HOLLYWOOD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
35	HOOD RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	HORNET SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	HUMBUG CREEK SUB	DISTRIBUTION-UNATTEN	67.00	12.50	
38	HUNTERS CIRCLE TEMP SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	ILLAHEE FLATS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
40	INDEPENDENCE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	

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 Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
25	1					1
13	1					2
25	1					3
50	2					4
95	4					5
50	2					6
7	1					7
25	2					8
20	1					9
45	2					10
20	1					11
19	2					12
12	1					13
25	1					14
21	4					15
5	3					16
20	1					17
25	2					18
6	1					19
12	1					20
11	3					21
6	1					22
20	1					23
45	2					24
25	1					25
20	1					26
8	3					27
13	1					28
6	3					29
40	1					30
45	2					31
20	1					32
75	3					33
50	2					34
40	2					35
20	1					36
9	1					37
12	1					38
2	1					39
20	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 2018/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	JACKSONVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	69.00
2	JEFFERSON SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
3	JEROME PRAIRIE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
4	JORDAN POINT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
5	JOSEPH SUB	DISTRIBUTION-UNATTEN	20.80	12.47	
6	JUNCTION CITY SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
7	KENWOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	KILLINGWORTH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	KNAPPA SVENSEN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
10	LAKEPORT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
11	LANCASTER SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
12	LEBANON SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
13	LINCOLN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
14	LOCKHART SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
15	LYONS SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
16	MADRAS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
17	MALLORY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
18	MARYS RIVER SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
19	MEDCO SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
20	MEDFORD	DISTRIBUTION-UNATTEN	115.00	12.47	
21	MERLIN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
22	MERRILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	MINAM SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	MODOC SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	MURDER CREEK SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
26	MYRTLE CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	MYRTLE POINT SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
28	NELSCOTT SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
29	NEW DESCHUTES SUB	DISTRIBUTION-UNATTEN	70.44	13.09	
30	NEW O'BRIEN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
31	OAK KNOLL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
32	OAKLAND SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
33	OREMET SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
34	OVERPASS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	PALLETTE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
36	PARK STREET SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
37	PARKROSE SUB	DISTRIBUTION-UNATTEN	120.00	13.20	
38	PENDLETON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	PILOT ROCK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	POWELL BUTTE 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 2018/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 Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
75	2					1
12	1					2
20	1					3
20	1					4
6	1	1				5
22	2					6
3	3					7
40	2					8
6	1					9
50	2					10
12	3					11
40	2					12
105	3					13
40	2					14
25	2					15
25	2					16
25	1					17
20	1					18
20	1					19
67	8					20
45	2					21
17	6					22
	1					23
6	3					24
100	4					25
14	1					26
9	1					27
4	1					28
25	1					29
9	1					30
45	2					31
8	1					32
75	2					33
45	2					34
1	1	1				35
40	2					36
37	2					37
46	7	1				38
22	2					39
12	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	PRINEVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
2	PROVOLT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	QUEEN AVE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
4	RED BLANKET SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
5	REDMOND SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
6	RIDDLE VENEER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
7	ROGUE RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	ROSEBURG SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
9	ROSS AVE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	ROXY ANN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
11	RUCH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
12	RUNNING Y SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
13	RUSSELLVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
14	SCENIC SUB	DISTRIBUTION-UNATTEN	115.00	12.47	69.00
15	SCIO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	SEASIDE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
17	SELMA SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
18	SHASTA WAY SUB	DISTRIBUTION-UNATTEN	12.47	4.16	
19	SHEVLIN PARK SUB	DISTRIBUTION-UNATTEN	69.00	12.50	
20	SIMTAG BOOSTER PUMP	DISTRIBUTION-UNATTEN	34.50	4.16	
21	SOUTH DUNES SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
22	SOUTHGATE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
23	SPRAGUE RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	STATE STREET SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
25	STAYTON SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
26	STEAMBOAT SUB	DISTRIBUTION-UNATTEN	115.00	7.20	
27	STEVENS ROAD SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
28	SUTHERLIN SUB	DISTRIBUTION-UNATTEN	115.00	12.00	
29	SWEET HOME SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
30	TAKELMA SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
31	TALENT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
32	TEXUM SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	TILLER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
34	TOLO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	TURKEY HILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	UMAPINE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	UMATILLA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	VERNON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
39	VILAS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
40	VILLAGE GREEN SUB	DISTRIBUTION-UNATTEN	115.00	20.80	

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 2018/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
11	3					2
50	2					3
2	3					4
50	2					5
25	1					6
25	2					7
50	2					8
9	3					9
25	1					10
9	1					11
9	1					12
45	2					13
70	3					14
8	1					15
40	2					16
9	1					17
2	3					18
25	1					19
19	2					20
9	1					21
20	1					22
7	3					23
40	2					24
55	2					25
	1					26
50	2					27
25	1					28
42	2					29
12	1					30
50	2					31
25	1					32
1	1					33
11	1					34
13	3					35
20	1					36
25	2					37
50	2					38
25	1					39
40	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 2018/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	VINE STREET SUB	DISTRIBUTION-UNATTEN	67.00	21.80	
2	WALLOWA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	WARM SPRINGS SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
4	WARRENTON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
5	WASCO SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
6	WECOMA BEACH SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
7	WESTON SUB	DISTRIBUTION-UNATTEN	70.60	13.09	
8	WESTSIDE HYDRO/SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	WEYERHAUSER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	WHITE CITY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
11	WILLOW COVE SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
12	WINSTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	YEW AVENUE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
14	YOUNGS BAY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
15	TOTAL (Number of Substations-176)		15500.31	2539.44	150.47
16					
17	ALBINA SUB	T/D-UNATTENDED	116.00		
18	APPLEGATE SUB	T/D-UNATTENDED	115.00	69.00	12.47
19	ASHLAND SUB	T/D-UNATTENDED	115.00	12.47	7.20
20	BEND PLANT SUB	T/D-UNATTENDED	69.00	13.09	12.47
21	CAVE JUNCTION SUB	T/D-UNATTENDED	115.00	12.47	69.00
22	HAZELWOOD SUB	T/D-UNATTENDED	115.00	69.00	12.47
23	KNOTT SUB	T/D-UNATTENDED	115.00	12.47	57.00
24	MILE HI SUB	T/D-UNATTENDED	115.00	69.00	12.47
25	PILOT BUTTE SUB	T/D-UNATTENDED	230.00	69.00	12.47
26	RIDDLE SUB	T/D-UNATTENDED	115.00	69.00	
27	SAGE ROAD SUB	T/D-UNATTENDED	115.00	12.47	
28	WINCHESTER SUB	T/D-UNATTENDED	115.00	12.47	69.00
29	TOTAL (Number of Substations-12)		1450.00	420.44	264.55
30					
31	LEMOLO #1 HYDRO	TRANSMISSION-ATTENDE	11.50	12.50	
32	CALAPOOYA SUB	TRANSMISSION-UNATTEN	230.00	69.00	
33	CHILOQUIN SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
34	COLD SPRINGS SUB	TRANSMISSION-UNATTEN	230.00	69.00	2.40
35	COVE SUB	TRANSMISSION-UNATTEN	230.00	69.00	
36	DIAMOND HILL SUB	TRANSMISSION-UNATTEN	230.00	69.00	
37	DIXONVILLE 115/230 SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
38	DIXONVILLE 500 SUB	TRANSMISSION-UNATTEN	500.00	230.00	
39	FISH HOLE SUB	TRANSMISSION-UNATTEN	115.00	69.00	
40	FRY SUB	TRANSMISSION-UNATTEN	230.00	115.00	

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 2018/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.
30	1					1
7	1					2
12	3					3
25	2					4
2	3					5
3	1					6
25	1					7
22	9					8
40	2					9
60	3					10
28	3					11
22	3					12
25	1					13
37	2					14
4653	335	5				15
						16
60	1	1				17
65	2					18
20	1					19
31	3					20
70	2					21
106	3					22
162	5					23
39	4					24
400	4					25
75	2					26
40	2					27
75	5					28
1143	34	1				29
						30
2	3					31
87	2					32
119	4					33
66	2					34
67	3					35
75	1					36
344	6					37
650	3	1				38
7	3					39
500	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	GRANTS PASS SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
2	HURRICANE SUB	TRANSMISSION-UNATTEN	230.00	69.00	2.40
3	ISTHMUS SUB	TRANSMISSION-UNATTEN	230.00	115.00	
4	KLAMATH FALLS SUB	TRANSMISSION-UNATTEN	230.00	69.00	
5	LONE PINE SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
6	MALIN SUB	TRANSMISSION-UNATTEN	500.00	230.00	69.00
7	MERIDIAN SUB	TRANSMISSION-UNATTEN	500.00	230.00	
8	MONPAC SUB	TRANSMISSION-UNATTEN	115.00	69.00	
9	NICKEL MOUNTAIN SUB	TRANSMISSION-UNATTEN	230.00	115.00	
10	PARRISH GAP SUB	TRANSMISSION-UNATTEN	230.00	69.00	12.47
11	PONDEROSA SUB	TRANSMISSION-UNATTEN	230.00	115.00	
12	PROSPECT CENTRAL SUB	TRANSMISSION-UNATTEN	115.00	69.00	
13	ROBERTS CREEK SUB	TRANSMISSION-UNATTEN	115.00	69.00	
14	ROUNDUP SUB - BPA	TRANSMISSION-UNATTEN	230.00	69.00	
15	SANTIAM TIE - BPA	TRANSMISSION-UNATTEN	230.00	69.00	
16	SNOW GOOSE SUB	TRANSMISSION-UNATTEN	525.00	230.00	34.50
17	TROUTDALE SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
18	TUCKER SUB	TRANSMISSION-UNATTEN	115.00	69.00	
19	WHETSTONE SUB	TRANSMISSION-UNATTEN	230.00	115.00	12.47
20	TOTAL (Number of Substations-29)		6981.50	3048.50	478.24
21					
22	UTAH				
23	106TH SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
24	118TH SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
25	23RD ST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	70TH SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
27	ALTAVIEW SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	AMALGA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	AMERICAN FORK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
30	ARAGONITE	DISTRIBUTION-UNATTEN	46.00	7.20	
31	AURORA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	BANGERTER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
33	BEAR RIVER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	BENJAMIN SUB	DISTRIBUTION-UNATTEN	46.20	12.47	
35	BINGHAM SUB	DISTRIBUTION-UNATTEN	46.00	7.62	
36	BLUE CREEK	DISTRIBUTION-UNATTEN	46.00	12.47	
37	BLUFF SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	BLUFFDALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	BOTHWELL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	BRIAN HEAD SUB	DISTRIBUTION-UNATTEN	34.50	12.47	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/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)	
583	4	3				1
29	2					2
250	1					3
251	6	1				4
733	10					5
775	4	1				6
1300	6	1				7
50	1					8
114	1					9
150	1					10
500	2					11
30	3					12
50	1					13
67	2					14
75	1					15
650	1	1				16
500	3					17
100	2					18
250	1					19
8374	81	8				20
						21
						22
30	1					23
30	1					24
12	1					25
30	1					26
45	2					27
11	1					28
30	1					29
1	1					30
3	1					31
50	2					32
17	2					33
4	1					34
25	1					35
2	3					36
1	3					37
9	1					38
4	1					39
14	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 2018/Q4

SUBSTATIONS

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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	BRIGHTON SUB	DISTRIBUTION-UNATTEN	46.00	24.90	
2	BROOKLAWN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	BRUNSWICK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	BURTON SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
5	BUSH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	CANNON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	CANYONLANDS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	CAPITOL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	CARBIDE SUB	DISTRIBUTION-UNATTEN	69.00	7.20	
10	CARBONVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	CARLISLE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
12	CASTO SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	CENTERVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	CENTRAL SUB	DISTRIBUTION-UNATTEN	43.80	12.47	
15	CHAPEL HILL SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
16	CHERRYWOOD SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
17	CIRCLEVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	CLEAR CREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	CLEAR LAKE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	CLEARFIELD SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
21	CLINTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
22	CLIVE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	COALVILLE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
24	COLD WATER CANYON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
25	COLEMAN SUB	DISTRIBUTION-UNATTEN	138.00	69.00	12.47
26	COLTON WELL SUB	DISTRIBUTION-UNATTEN	46.00	2.40	
27	COMMERCE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
28	COPPER HILLS SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
29	CORINNE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	COVE FORT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	COZYDALE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
32	CROSS HOLLOW SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
33	CUDAHY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
34	DAMMERON VALLEY SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
35	DECKER LAKE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
36	DELLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	DELTA SUB	DISTRIBUTION-UNATTEN	46.00	69.00	
38	DEWEYVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	DIMPLE DELL SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
40	DRAPER 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 2018/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 Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
29	2					1
6	1					2
60	3					3
11	3					4
9	1					5
12	1					6
1	1					7
20	1					8
3	1					9
6	1					10
30	1					11
25	1					12
22	1					13
9	1					14
30	1					15
50	2					16
3	1					17
4	1					18
	3					19
60	2					20
50	2					21
4	1					22
22	1					23
30	1					24
106	4					25
1	3					26
30	1					27
30	1					28
3	1					29
2	3					30
30	1					31
22	1					32
30	1					33
42	1					34
55	2					35
6	1					36
48	3					37
4	1					38
60	2					39
23	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 2018/Q4

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	EAST BENCH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
2	EAST HYRUM SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	EAST LAYTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
4	EAST MILLCREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	EDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	ELBERTA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	ELK MEADOWS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
8	ELSINORE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	EMERY CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	EMIGRATION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	ENOCH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
12	ENTERPRISE VALLEY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
13	EUREKA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	FARMINGTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
15	FAYETTE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	FERRON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
17	FIELDING SUB	DISTRIBUTION-UNATTEN	46.00	12.00	
18	FIFTH WEST SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
19	FLUX SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	FOOL CREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	FORT DOUGLAS	DISTRIBUTION-UNATTEN	138.00	13.20	
22	FOUNTAIN GREEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	FREEDOM SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
24	FRUIT HEIGHTS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	GARDEN CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	GATEWAY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	GOLD RUSH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
28	GORDON AVENUE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
29	GOSHEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	GRANGER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	GRANTSVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	GUNNISON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	HAMMER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
34	HAVASU SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	HELPER CITY SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
36	HERRIMAN SUB	DISTRIBUTION-UNATTEN	138.00	13.20	
37	HIGHLAND DIST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	HOGGARD SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
39	HOLDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	HOLLADAY 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.
30	1					1
6	1					2
60	2					3
20	1					4
19	2					5
5	1					6
3	1					7
2	1					8
3	3					9
25	1					10
14	1					11
10	1					12
3	1					13
30	1					14
1	2					15
5	1					16
6	1					17
50	2					18
4	1					19
2	1					20
40	1					21
7	1					22
	1					23
22	1					24
12	1					25
14	1	2				26
30	1					27
30	1					28
2	1					29
50	2					30
23	1					31
11	2					32
60	2					33
3	1					34
3	3					35
60	2					36
25	1					37
50	2					38
4	1					39
32	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 2018/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	HUNTER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	HUNTINGTON CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	IRON MOUNTAIN SUB	DISTRIBUTION-UNATTEN	34.50	7.20	
4	IRONTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	IVINS SUB	DISTRIBUTION-UNATTEN	67.00	12.47	
6	JORDAN NARROWS SUB	DISTRIBUTION-UNATTEN	46.00	2.40	
7	JORDAN PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
8	JORDANELLE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
9	JUAB SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	JUNCTION SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
11	KAIBAB SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
12	KAMAS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	KEARNS SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
14	KENSINGTON SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
15	KYUNE SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
16	LAKE PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
17	LAYTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	LEGRANDE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	LEWISTON SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
20	LINCOLN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	LINDON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	LISBON SUB	DISTRIBUTION-UNATTEN	70.60	12.47	
23	LOAFER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	LOGAN CANYON SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
25	LONE TREE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
26	LOWER BEAVER SUB	DISTRIBUTION-UNATTEN	46.00	6.60	
27	LYNNDYL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	MAESER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
29	MAGNA SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
30	MANILA SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
31	MANTUA SUB	DISTRIBUTION-UNATTEN	44.00	12.47	
32	MAPLETON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	MARRIOTT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	MARYSVALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	MATHIS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	MCCORNICK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	MCKAY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	MEADOWBROOK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	46.00
39	MEDICAL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	MIDLAND SUB	DISTRIBUTION-UNATTEN	138.00	12.47	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Total Capacity (In MVa) (k)	Line No.
22	1					1
12	2					2
1	1					3
2	1					4
30	1					5
13	2					6
30	1					7
30	1					8
4	1					9
3	1					10
5	1					11
7	1					12
60	2					13
7	1					14
	1					15
53	2					16
40	2					17
2	1					18
22	1					19
20	1					20
20	1					21
3	1					22
	1					23
1	1					24
20	1					25
1	1					26
4	1					27
12	1					28
30	1					29
22	1					30
2	1					31
14	1					32
20	1					33
3	1					34
9	1					35
6	1					36
20	1					37
42	2					38
57	4					39
30	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	MIDVALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	MILFORD SUB	DISTRIBUTION-UNATTEN	138.00	46.00	
3	MILFORD TV SUB	DISTRIBUTION-UNATTEN	46.00	13.20	
4	MINERSVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	MOAB CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	MOORE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	MORGAN SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
8	MORONI SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	MOUNTAIN DELL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	MOUNTAIN GREEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	MYTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
12	NEW HARMONY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	NEWGATE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	NEWTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	NIBLEY SUB	DISTRIBUTION-UNATTEN	138.00	24.90	
16	NORTH BENCH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	NORTH FIELDS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	NORTH LOGAN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	NORTH OGDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	NORTH SALT LAKE SUB	DISTRIBUTION-UNATTEN	46.00	13.20	
21	NORTHEAST SUB	DISTRIBUTION-UNATTEN	46.00	12.50	
22	NORTHRIDGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	OAKLAND AVE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	OAKLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	OLYMPUS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	OPHIR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
27	ORANGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	ORANGEVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
29	OREM SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	PACK CREEK RESERVOIR	DISTRIBUTION-UNATTEN	46.00	12.47	
31	PANGUITCH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	PARIETTE SUB	DISTRIBUTION-UNATTEN	69.00	24.94	
33	PARK CITY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	PARKSIDE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
35	PARKWAY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
36	PARLEYS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	PELICAN POINT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	PINE CANYON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
39	PINE CREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	PINNACLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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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
89	2					2
	1					3
2	1					4
19	2					5
3	1					6
7	2					7
6	1					8
5	1					9
6	1					10
6	1					11
7	1					12
20	1					13
5	1					14
14	1					15
25	1					16
2	1					17
25	1					18
22	1					19
25	1					20
45	2					21
14	1					22
24	2					23
6	1					24
22	1					25
3	1					26
20	1					27
14	1					28
48	2					29
4	1					30
5	1					31
14	1					32
42	2					33
60	2					34
50	2					35
16	2					36
6	1					37
55	2					38
2	1					39
14	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 2018/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	PLAIN CITY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
2	PLEASANT GROVE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
3	PLEASANT VIEW SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	PONY EXPRESS SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
5	PORTER ROCKWELL SUB	DISTRIBUTION-UNATTEN	138.00	13.20	
6	PROMONTORY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	QUAIL CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	QUARRY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
9	QUICHAPA SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
10	RAINS SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
11	RANDOLPH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	RASMUSON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	RATTLESNAKE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
14	RED MOUNTAIN SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
15	REDWOOD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	RESEARCH PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	RICH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	RICHFIELD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	RICHMOND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	RIDGELAND SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
21	RITER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	ROCK CANYON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	ROCKVILLE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
24	ROCKY POINT	DISTRIBUTION-UNATTEN	138.00	13.20	
25	ROSE PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	ROYAL SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
27	SALINA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	SANDY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
29	SARATOGA SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
30	SCIPIO SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	SCOFIELD RESERVOIR SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
32	SCOFIELD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	SEGO CANYON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	SEVEN MILE SUB	DISTRIBUTION-UNATTEN	68.68	7.20	
35	SHARON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	SHORELINE SUB	DISTRIBUTION-UNATTEN	138.00	13.20	
37	SIXTH SOUTH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	SKULL VALLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	SKYPARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	12.47
40	SNARR 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 2018/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.
22	1					1
25	1					2
14	1					3
60	2					4
60	2					5
2	1					6
4	1					7
60	2					8
4	1					9
15	1					10
2	1					11
1	3					12
14	1					13
12	1					14
45	2					15
45	2					16
5	1					17
22	2					18
11	1					19
40	2					20
20	1					21
5	1					22
4	1					23
30	1					24
24	3					25
	3					26
11	1					27
60	2					28
60	2					29
1	3					30
1	1					31
1	3					32
14	1					33
	1					34
20	1					35
60	2					36
20	1					37
2	1					38
40	1					39
40	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	SNOWVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
2	SNYDERVILLE SUB	DISTRIBUTION-UNATTEN	138.00	46.00	
3	SOLDIER SUMMIT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	SOUTH JORDAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
5	SOUTH MILFORD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	SOUTH MOUNTAIN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
7	SOUTH OGDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
8	SOUTH PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
9	SOUTH WEBER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
10	SOUTHWEST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	SPANISH VALLEY SUB	DISTRIBUTION-UNATTEN	67.00	12.47	
12	SPRINGDALE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
13	ST. JOHNS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	STANSBURY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	SUMMIT CREEK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
16	SUMMIT PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	SUNRISE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
18	SUTHERLAND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	TAMARISK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
20	TAYLOR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	THIEF CREEK SUB	DISTRIBUTION-UNATTEN	138.00	24.90	
22	THIRD WEST SUB	DISTRIBUTION-UNATTEN	138.00	13.20	
23	THIRTEENTH SOUTH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	TOOELE DEPOT SUB	DISTRIBUTION-UNATTEN	46.00	12.50	
25	TOQUERVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	34.50
26	UINTAH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
27	UNION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	VALLEY CENTER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	VERMILLION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	VERNAL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	VICKERS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	VINEYARD SUB	DISTRIBUTION-UNATTEN	138.00	13.20	
33	WALLSBURG SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
34	WALNUT GROVE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
35	WARREN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
36	WASATCH STATE PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	WASHAKIE SUB	DISTRIBUTION-UNATTEN	138.00	4.16	
38	WELBY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	WELFARE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	WEST COMMERCIAL 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.
5	1					1
127	3					2
12	1					3
60	2					4
28	2					5
60	2					6
25	1					7
30	1					8
22	1					9
22	2					10
14	1					11
4	1					12
4	1					13
20	1					14
14	1					15
7	1					16
60	2					17
6	1					18
20	1					19
14	1					20
14	1					21
100	2					22
22	1					23
25	1					24
34	2					25
39	2					26
50	2					27
22	1					28
3	1					29
33	2					30
2	1					31
30	1					32
13	1					33
30	1					34
30	1					35
2	3					36
14	1					37
42	2					38
10	1					39
22	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	WEST JORDAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
2	WEST OGDEN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
3	WEST POINT SUB	DISTRIBUTION-UNATTEN	138.00	13.20	
4	WEST ROY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	WEST TEMPLE SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
6	WESTWATER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	WHITE ROCK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
8	WILLOWCREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	WILLOWRIDGE SUB	DISTRIBUTION-UNATTEN	44.90	12.47	
10	WINCHESTER HILLS SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
11	WINKLEMAN SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
12	WOLF CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	WOOD CROSS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	WOODRUFF SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	TOTAL (Number of Substations-272)		20128.68	3524.38	105.44
16					
17	90TH SOUTH SUB	T/D-UNATTENDED	345.00	138.00	12.47
18	ANGEL SUB	T/D-UNATTENDED	138.00	12.47	46.00
19	BDO SUB	T/D-UNATTENDED	138.00	12.47	
20	BUTLERVILLE SUB	T/D-UNATTENDED	138.00	46.00	12.47
21	CENTENNIAL SUB	T/D-UNATTENDED	138.00	12.47	
22	COTTONWOOD SUB	T/D-UNATTENDED	138.00	12.47	46.00
23	DECADE SUB	T/D-UNATTENDED	138.00	12.47	
24	DUMAS SUB	T/D-UNATTENDED	138.00	12.47	
25	EMMA PARK SUB	T/D-UNATTENDED	138.00	12.47	
26	GROW SUB	T/D-UNATTENDED	138.00	12.47	46.00
27	HALE SUB	T/D-UNATTENDED	138.00	46.00	12.47
28	HIGHLAND SUB	T/D-UNATTENDED	138.00	12.47	46.00
29	JORDAN SUB	T/D-UNATTENDED	138.00	46.00	12.47
30	JUDGE SUB	T/D-UNATTENDED	46.00	12.47	
31	MCCLELLAND SUB	T/D-UNATTENDED	138.00	46.00	12.47
32	MORTON COURT SUB	T/D-UNATTENDED	138.00	12.47	
33	OQUIRRH SUB	T/D-UNATTENDED	345.00	46.00	138.00
34	PARRISH SUB	T/D-UNATTENDED	138.00	12.47	46.00
35	PIONEER PLANT	T/D-UNATTENDED	138.00	12.47	
36	RIVERDALE SUB	T/D-UNATTENDED	138.00	46.00	12.47
37	SEVIER SUB	T/D-UNATTENDED	138.00	46.00	12.47
38	SILVER CREEK SUB	T/D-UNATTENDED	138.00	12.47	46.00
39	SOUTHEAST SUB	T/D-UNATTENDED	138.00	12.47	46.00
40	SYRACUSE SUB	T/D-UNATTENDED	345.00	138.00	46.00

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 2018/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.
28	1					1
60	2					2
40	1					3
25	1					4
60	3					5
5	1					6
30	1					7
1	1					8
24	1					9
4	1					10
	1					11
6	1					12
20	1					13
2	1					14
5810	374	2				15
						16
1572	5					17
135	3					18
30	1					19
205	4					20
40	2					21
289	7					22
60	2					23
60	2					24
8	1					25
72	3					26
114	2					27
97	2					28
164	2					29
22	1					30
340	3					31
65	2					32
835	4	1				33
97	2					34
30	1					35
180	3					36
34	4					37
100	2					38
50	2					39
1300	6					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 2018/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	TAYLORSVILLE SUB	T/D-UNATTENDED	138.00	46.00	12.47
2	TERMINAL SUB	T/D-UNATTENDED	345.00	46.00	138.00
3	TIMP SUB	T/D-UNATTENDED	138.00	46.00	12.47
4	TOOELE SUB	T/D-UNATTENDED	138.00	46.00	12.47
5	TRI CITY SUB	T/D-UNATTENDED	138.00	12.47	
6	WEST VALLEY SUB	T/D-UNATTENDED	138.00	12.47	
7	WESTFIELD SUB	T/D-UNATTENDED	138.00	12.47	
8	TOTAL (Number of Substations-31)		5014.00	1006.46	768.70
9					
10	EMERY SUB	TRANSMISSION-ATTENDE	345.00	138.00	69.00
11	GADSBY SUB	TRANSMISSION-ATTENDE	138.00	46.00	
12	ABAJO SUB	TRANSMISSION-UNATTEN	138.00	69.00	
13	ASHLEY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
14	BARNEY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
15	BEN LOMOND SUB	TRANSMISSION-UNATTEN	345.00	230.00	138.00
16	BLACK ROCK SUB	TRANSMISSION-UNATTEN	230.00	69.00	
17	BLACKHAWK SUB	TRANSMISSION-UNATTEN	138.00	69.00	46.00
18	CAMERON SUB	TRANSMISSION-UNATTEN	138.00	46.00	
19	CAMP WILLIAMS SUB	TRANSMISSION-UNATTEN	345.00	138.00	12.47
20	CLOVER SUB	TRANSMISSION-UNATTEN	345.00	138.00	14.40
21	COLUMBIA SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
22	CRANER FLAT SUB	TRANSMISSION-UNATTEN	138.00	12.47	
23	CROYDON SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
24	CUTLER SUB	TRANSMISSION-UNATTEN	138.00	46.00	
25	EL MONTE SUB	TRANSMISSION-UNATTEN	138.00	46.00	
26	GARKANE SUB	TRANSMISSION-UNATTEN	69.00	46.00	
27	GREEN CANYON SUB	TRANSMISSION-UNATTEN	138.00	46.00	
28	GRINDING SUB	TRANSMISSION-UNATTEN	138.00	13.80	
29	HELPER SUB	TRANSMISSION-UNATTEN	138.00	46.00	
30	HONEYVILLE SUB	TRANSMISSION-UNATTEN	138.00	46.00	
31	HORSESHOE SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
32	HUNTINGTON SUB	TRANSMISSION-UNATTEN	345.00	138.00	24.90
33	JERUSALEM SUB	TRANSMISSION-UNATTEN	138.00	46.00	
34	LAMPO SUB	TRANSMISSION-UNATTEN	138.00	46.00	
35	MATHINGTON SUB	TRANSMISSION-UNATTEN	138.00	46.00	13.20
36	MCFADDEN SUB	TRANSMISSION-UNATTEN	138.00	46.00	
37	MIDDLETON SUB	TRANSMISSION-UNATTEN	138.00	69.00	34.50
38	MIDVALLEY SUB	TRANSMISSION-UNATTEN	345.00	138.00	
39	MIDWAY CITY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
40	MINERAL PRODUCTS SUB	TRANSMISSION-UNATTEN	69.00	46.00	

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 2018/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.
358	4					1
1108	6	2				2
130	2					3
249	3					4
30	1					5
30	1					6
20	1					7
7824	84	3				8
						9
783	13					10
318	2					11
67	1					12
133	2					13
100	1					14
1813	5					15
75	1					16
100	2					17
25	4					18
169	2					19
448	1					20
71	2					21
40	2					22
81	2					23
50	1					24
312	3					25
33	1					26
67	2					27
225	3					28
77	2					29
35	1					30
80	2					31
270	4					32
67	1					33
75	1					34
160	5	1				35
45	1					36
137	3					37
900	2					38
67	1					39
12	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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	MOAB SUB	TRANSMISSION-UNATTEN	138.00	69.00	
2	NEBO SUB	TRANSMISSION-UNATTEN	138.00	46.00	
3	PAROWAN VALLEY SUB	TRANSMISSION-UNATTEN	230.00	138.00	34.50
4	PAVANT SUB	TRANSMISSION-UNATTEN	230.00	46.00	
5	PINTO SUB	TRANSMISSION-UNATTEN	345.00	138.00	69.00
6	PURGATORY FLAT SUBSTATION	TRANSMISSION-UNATTEN	138.00	69.00	12.47
7	RED BUTTE SUB	TRANSMISSION-UNATTEN	345.00	138.00	
8	SIGURD SUB	TRANSMISSION-UNATTEN	345.00	230.00	138.00
9	SMITHFIELD SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
10	SPANISH FORK SUB	TRANSMISSION-UNATTEN	345.00	138.00	46.00
11	ST GEORGE SUB	TRANSMISSION-UNATTEN	138.00	16.50	
12	THREE PEAKS SUB	TRANSMISSION-UNATTEN	345.00	138.00	
13	WEST CEDAR SUB	TRANSMISSION-UNATTEN	230.00	138.00	34.50
14	TOTAL (Number of Substations-44)		8579.00	3446.77	736.82
15					
16	WASHINGTON				
17	ATTALIA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	BOWMAN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	CASCADE KRAFT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	4.16
20	CLINTON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
21	DAYTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	DODD ROAD SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
23	GRANDVIEW SUB	DISTRIBUTION-UNATTEN	115.00	12.47	69.00
24	GROMORE SUB	DISTRIBUTION-UNATTEN	116.00	13.20	
25	HOPLAND SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
26	NACHES SUB	DISTRIBUTION-UNATTEN	115.00	12.00	
27	NOB HILL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
28	NORTH PARK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
29	ORCHARD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
30	PACIFIC SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
31	POMEROY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	PROSPECT POINT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	PUNKIN CENTER SUB	DISTRIBUTION-UNATTEN	116.00	13.20	
34	RIVER ROAD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
35	SELAH SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
36	SULPHUR CREEK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
37	SUNNYSIDE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
38	TIETON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	34.50
39	TOPPENISH SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
40	TOUCHET SUB	DISTRIBUTION-UNATTEN	69.00	12.47	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	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)	
67	1					1
67	1					2
138	2					3
133	2					4
258	3					5
300	2					6
414	2					7
1124	6					8
63	2					9
1100	2					10
100	3	1				11
450	1					12
262	3					13
11311	104	2				14
						15
						16
25	1					17
45	2					18
118	6					19
25	1					20
23	2					21
25	4					22
42	2					23
25	1					24
50	2					25
25	1					26
42	2					27
45	2					28
50	2					29
28	3					30
9	1					31
40	2					32
44	3					33
76	5					34
45	2					35
25	1					36
45	2					37
29	2					38
50	2					39
6	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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	VOELKER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
2	WAITSBURG SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	WAPATO SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
4	WENAS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
5	WHITE SWAN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
6	WILEY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
7	TOTAL (Number of Substations-30)		3038.00	383.42	107.66
8					
9	CENTRAL SUB	T/D-UNATTENDED	69.00	12.47	
10	MILL CREEK SUB	T/D-UNATTENDED	69.00	12.47	
11	UNION GAP SUB	T/D-UNATTENDED	230.00	115.00	12.47
12	TOTAL (Number of Substations-3)		368.00	139.94	12.47
13					
14	DRY GULCH SUB - AVISTA	TRANSMISSION-UNATTEN	115.00	69.00	
15	OUTLOOK SUB	TRANSMISSION-UNATTEN	230.00	115.00	
16	PASCO SUB	TRANSMISSION-UNATTEN	115.00	69.00	7.20
17	POMONA HEIGHTS SUB	TRANSMISSION-UNATTEN	230.00	115.00	13.20
18	WALLA WALLA 230KV SUB	TRANSMISSION-UNATTEN	230.00	69.00	
19	WALLULA SUB	TRANSMISSION-UNATTEN	230.00	69.00	
20	WINE COUNTRY SUB	TRANSMISSION-UNATTEN	230.00	115.00	
21	TOTAL (Number of Substations-7)		1380.00	621.00	20.40
22					
23	WYOMING				
24	ANTELOPE MINE SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
25	ARROWHEAD SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
26	ASTLE STREET	DISTRIBUTION-UNATTEN	34.50	13.20	
27	BAILEY DOME SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
28	BAR NUNN	DISTRIBUTION-UNATTEN	115.00	12.47	
29	BAR X SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
30	BIG MUDDY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	BIG PINEY SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
32	BLACKS FORK SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
33	BRIDGER PUMP SUB	DISTRIBUTION-UNATTEN	230.00	34.50	13.20
34	BRYAN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
35	BYRON SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
36	CASSA SUB	DISTRIBUTION-UNATTEN	57.00	20.80	12.47
37	CENTER STREET SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
38	CHAPMAN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	CHUKAR SUB	DISTRIBUTION-UNATTEN	12.47	4.16	
40	CHURCH AND DWIGHT SUB	DISTRIBUTION-UNATTEN	34.50	0.48	

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
9	1					2
45	2					3
25	2					4
22	2					5
45	2					6
1108	62					7
						8
14	1					9
45	2					10
595	5					11
654	8					12
						13
20	1					14
125	1					15
39	9					16
325	3					17
300	2					18
120	2					19
250	1					20
1179	19					21
						22
						23
25	1					24
150	2					25
13	1					26
2	1					27
30	1					28
25	1					29
7	1					30
14	1					31
150	2					32
73	4					33
25	1					34
2	3					35
2	6					36
12	1					37
4	1					38
1	3					39
1	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 2018/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	COKEVILLE SUB	DISTRIBUTION-UNATTEN	46.00	24.90	
2	COLUMBIA-GENEVA SUB	DISTRIBUTION-UNATTEN	230.00	13.80	
3	COMMUNITY PARK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
4	CROOKS GAP SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
5	DEER CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	DJ COAL MINE SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
7	DOUGLAS SUB	DISTRIBUTION-UNATTEN	57.00	4.16	
8	DRY FORK SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
9	ELK BASIN SUB	DISTRIBUTION-UNATTEN	34.50	7.20	
10	EMIGRANT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
11	EVANS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
12	EVANSTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
13	FORT CASPER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	FORT SANDERS SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
15	FRANNIE SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
16	FRONTIER SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
17	GARLAND SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
18	GLENDO SUB	DISTRIBUTION-UNATTEN	57.00	4.16	
19	GRASS CREEK SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
20	GREAT DIVIDE SUB	DISTRIBUTION-UNATTEN	115.00	34.50	
21	GREYBULL SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
22	HANNA SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
23	JACKALOPE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
24	KEMMERER SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
25	KIRBY CREEK PUMPING STATION	DISTRIBUTION-UNATTEN	34.50	2.40	
26	KIRBY CREEK SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
27	LANDER SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
28	LARAMIE SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
29	LATHAM SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
30	LINCH SUB	DISTRIBUTION-UNATTEN	69.00	13.80	
31	LITTLE MOUNTAIN SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
32	LOVELL SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
33	MILL IRON SUB	DISTRIBUTION-UNATTEN	34.50	13.80	
34	MILLS SUB	DISTRIBUTION-UNATTEN	12.47	4.16	
35	MURPHY DOME SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
36	NUGGETT SUB	DISTRIBUTION-UNATTEN	69.00	7.20	
37	OPAL SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
38	ORIN SUB	DISTRIBUTION-UNATTEN	57.00	7.20	
39	ORPHA SUB	DISTRIBUTION-UNATTEN	57.00	7.20	
40	PARADISE SUB	DISTRIBUTION-UNATTEN	69.00	25.00	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	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
45	2					2
50	2					3
5	3					4
9	1					5
12	1					6
6	1					7
9	1					8
5	1					9
12	1					10
9	1					11
40	2					12
28	1					13
20	1					14
50	2					15
6	1					16
45	2					17
1	3					18
25	1					19
20	1					20
3	1					21
6	1					22
25	1					23
14	1					24
3	3					25
2	3					26
25	2					27
50	2					28
25	1					29
12	1					30
20	1					31
4	1					32
12	1					33
1	3					34
5	1					35
	1					36
8	1					37
1	1					38
3	3					39
30	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	PARCO SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
2	PINEDALE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
3	PITCHFORK SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
4	POISON SPIDER SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
5	POLECAT SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
6	RAINBOW SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
7	RAVEN SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
8	RED BUTTE SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
9	REFINERY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
10	SAGE HILL SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
11	SHOSHONI SUB	DISTRIBUTION-UNATTEN	34.50	2.40	
12	SLATE CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	SOUTH CODY SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
14	SOUTH ELK BASIN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
15	SOUTH TRONA SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
16	SPRING CREEK SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
17	SVILAR SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
18	TEN MILE STEP DOWN SUB	DISTRIBUTION-UNATTEN	34.50	12.50	
19	TEN MILE SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
20	THERMOPOLIS TOWN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
21	THUNDER CREEK SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
22	VETERANS SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
23	WAPA THERMOPOLIS	DISTRIBUTION-UNATTEN	115.00	34.50	
24	WERTZ-SINCLAIR SUB	DISTRIBUTION-UNATTEN	57.00	4.16	12.50
25	WEST ADAMS SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
26	WESTVACO SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
27	WORLAND TOWN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
28	WYOPO SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
29	TOTAL (Number of Substations-85)		7875.44	1378.71	38.17
30					
31	BUFFALO SUB	T/D-UNATTENDED	230.00	20.80	
32	ELK HORN SUB	T/D-UNATTENDED	115.00	12.47	
33	FIREHOLE SUB	T/D-UNATTENDED	230.00	34.50	
34	HILLTOP SUB	T/D-UNATTENDED	115.00	34.50	20.80
35	LABARGE SUB	T/D-UNATTENDED	69.00	24.90	
36	POINT OF ROCKS SUB	T/D-UNATTENDED	230.00	34.50	
37	RIVERTON 230 SUB	T/D-UNATTENDED	230.00	12.47	34.50
38	YELLOWCAKE SUB	T/D-UNATTENDED	230.00	34.50	
39	TOTAL (Number of Substations-8)		1449.00	208.64	55.30
40					

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)	
5	1					1
20	1					2
16	9	2				3
3	1					4
2	3					5
12	1					6
200	2					7
30	1					8
45	2					9
6	1					10
2	3					11
1	1					12
14	3	1				13
2	6					14
150	2					15
28	1					16
2	3					17
5	1					18
12	1					19
5	1					20
9	1					21
25	2					22
25	1					23
2	6					24
3	1					25
25	1					26
5	1					27
20	1	1				28
1860	148	4				29
						30
20	1	1				31
25	1					32
50	2					33
45	2	1				34
8	6					35
25	1					36
76	4					37
25	1					38
274	18	2				39
						40

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/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	DAVE JOHNSTON PLANT/SUB	TRANSMISSION-ATTENDE	230.00	115.00	69.00
2	JIM BRIDGER 345KV SUB	TRANSMISSION-ATTENDE	345.00	230.00	34.50
3	NAUGHTON SUB	TRANSMISSION-ATTENDE	230.00	138.00	69.00
4	BAIROIL SUB	TRANSMISSION-UNATTEN	115.00	34.50	57.00
5	CASPER SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
6	CHAPPEL CREEK SUB	TRANSMISSION-UNATTEN	230.00	69.00	
7	CHIMNEY BUTTE SUB	TRANSMISSION-UNATTEN	230.00	69.00	
8	FOOTE CREEK WIND FARM	TRANSMISSION-UNATTEN	230.00	34.50	
9	GLENDO AUTO SUB	TRANSMISSION-UNATTEN	69.00	57.00	
10	MANSFACE SUB	TRANSMISSION-UNATTEN	230.00	34.50	
11	MIDWEST SUB	TRANSMISSION-UNATTEN	230.00	69.00	34.50
12	MINERS SUB	TRANSMISSION-UNATTEN	230.00	34.50	9.70
13	MUSTANG SUB	TRANSMISSION-UNATTEN	230.00	115.00	
14	OREGON BASIN SUB	TRANSMISSION-UNATTEN	230.00	69.00	34.50
15	PLATTE SUB	TRANSMISSION-UNATTEN	230.00	115.00	34.50
16	RAILROAD SUB	TRANSMISSION-UNATTEN	230.00	138.00	
17	ROCK SPRINGS 230 SUB	TRANSMISSION-UNATTEN	230.00	34.50	
18	SAGE SUB	TRANSMISSION-UNATTEN	69.00	46.00	
19	STANDPIPE SUB	TRANSMISSION-UNATTEN	230.00	12.47	
20	THERMOPOLIS SUB	TRANSMISSION-UNATTEN	230.00	115.00	
21	TOTAL (Number of Substations-20)		4278.00	1644.97	411.70
22					
23	CALIFORNIA				
24	Distribution - 42				
25	T/D - 2				
26	Transmission - 5				
27					
28	IDAHO				
29	Distribution - 65				
30	T/D - 5				
31	Transmission - 18				
32					
33	MONTANA				
34	Transmission - 3				
35					
36	OREGON				
37	Distribution - 176				
38	T/D - 12				
39	Transmission - 29				
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 2018/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.
303	3	1				1
703	7					2
661	4					3
53	3					4
575	4					5
75	1					6
75	1					7
196	2					8
8	1	1				9
20	1					10
157	3					11
20	1					12
100	1					13
100	2					14
140	3					15
400	1					16
50	2					17
22	1					18
75	1					19
84	1					20
3817	43	2				21
						22
						23
323						24
130						25
725						26
						27
						28
736						29
312						30
5111						31
						32
						33
200						34
						35
						36
4653						37
1143						38
8374						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 2018/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	UTAH				
2	Distribution - 272				
3	T/D - 31				
4	Transmission - 44				
5					
6	WASHINGTON				
7	Distribution - 30				
8	T/D - 3				
9	Transmission - 7				
10					
11	WYOMING				
12	Distribution - 85				
13	T/D - 8				
14	Transmission - 20				
15					
16	ALL STATES				
17	Distribution - 670				
18	T/D - 61				
19	Transmission - 126				
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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
5810						2
7824						3
11311						4
						5
						6
1108						7
654						8
1179						9
						10
						11
1860						12
274						13
3817						14
						15
						16
14490						17
10337						18
30717						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Schedule Page: 426.3 Line No.: 13 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.: 15 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.: 20 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.: 22 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.: 23 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.: 23 Column: g

Represents one 3-phase bank

Schedule Page: 426.3 Line No.: 27 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.: 33 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.: 34 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: 426.8 Line No.: 38 Column: a

The Dixonville 500kV Substation is jointly owned by PacifiCorp and Bonneville Power Administration ("BPA"), each with an undivided interest of 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.: 2 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.: 6 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 as defined in the operation and maintenance agreement.

Schedule Page: 426.9 Line No.: 7 Column: a

The Meridian 500kV Substation is jointly owned by PacifiCorp and BPA, each with an undivided interest of 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 Roundup 230kV Substation property is owned by PacifiCorp and BPA as defined in the facility sharing agreement where operation and maintenance costs vary by type of asset and performance responsibility.

Schedule Page: 426.9 Line No.: 15 Column: a

The Santiam Tie 230kV Substation property is owned by PacifiCorp and BPA as defined in the facility sharing agreement where operation and maintenance costs vary by type of asset and performance responsibility.

Schedule Page: 426.19 Line No.: 14 Column: a

The Dry Gulch 115kV Substation property is owned by PacifiCorp and Avista Corporation as defined in the interconnection agreement where operation and maintenance costs vary by type of asset and performance responsibility.

Schedule Page: 426.19 Line No.: 18 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.: 1 Column: a

The Dave Johnston 230kV Substation is jointly owned by PacifiCorp and Black Hills Power with an undivided interest of 85.0% and 15.0%, respectively. 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.: 2 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 2018/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	170,644,431
3	Coal purchases	Trapper Mining Inc.	151,501	14,501,341
4	Administrative services under the IASA	BHE		5,165,883
5	Administrative services under the IASA	MEC		4,465,031
6	Administrative services under the IASA	BHE U.S. Transmission, LLC	426.5,923	1,199,006
7	Administrative services under the IASA	MHC Inc.	426.5	499,935
8	Administrative services under the IASA	Kern River Gas Transmission Company	923	104
9	Gas transportation services	Kern River Gas Transmission Company	547	3,072,669
10	Rail services and right-of-way fees	BNSF Railway Company	151,501,567,589	32,526,666
11	Employee relocation services	HomeServices of America, Inc.		1,429,105
12	Travel services	Delta Air Lines, Inc.		1,152,381
13	Operational support services	Marmon Utility, LLC	593	397,298
14	Banking services	Wells Fargo & Company		1,125,775
15	Banking services and rating agency fees	U.S. Bancorp		401,092
16	Rating agency fees	Moody's Investors Service, Inc.	181,427,930.2	371,157
17	Lubricating oil and grease products	Phillips 66		719,174
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Information technology and administrative			
22	support services	Bridger Coal Company	501,557,931	1,409,166
23	Administrative services under the IASA	MEC		485,465
24	Administrative services under the IASA	NV Energy, Inc.		116,005
25	Operational support services	NV Energy, Inc.	416	172,998
26	Financial transactions related to energy hedging	Wells Fargo & Company		1,781,225
27				
28				
29				
30				
31				
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41				
42				

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.

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 for BHE: 107, 426.4, 426.5, 921 and 923.

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 for MEC: 107, 426.4, 426.5 and 923.

Schedule Page: 429 Line No.: 10 Column: d

Non-power goods or services provided by BNSF Railway Company are as follows:

$32,489,102	Rail services
37,564	Right-of-way fees
$32,526,666	

Included in the right-of-way fees are amounts related to jointly-owned facilities that are paid either directly or indirectly to BNSF Railway Company.

Schedule Page: 429 Line No.: 11 Column: c

Accounts charged for HomeServices of America, Inc.: 506, 535, 539, 548, 553, 557, 560, 561.2, 561.5, 570, 580, 581, 590, 592, 593, 901, 903, 908 and 921.

Schedule Page: 429 Line No.: 12 Column: c

Accounts charged for Delta Air Lines, Inc.: 426.4, 426.5, 500, 501, 502, 506, 512, 513, 514, 535, 539, 546, 548, 549, 553, 554, 556, 557, 560, 561.2, 561.5, 561.7, 568, 569.3, 571, 580, 581, 585, 588, 590, 592, 593, 595, 598, 901, 903, 908, 909, 920, 921, 922 and 928.

Schedule Page: 429 Line No.: 14 Column: c

Accounts charged for Wells Fargo & Company: 228.3, 419, 426.5, 427, 431, 501, 903, 921 and 928.

Schedule Page: 429 Line No.: 15 Column: c

Accounts charged for U.S. Bancorp, including its subsidiary U.S. Bank National Association: 419, 427, 431, 537, 557, 560, 903, 921, 928 and 930.2.

Schedule Page: 429 Line No.: 17 Column: c

Accounts charged for Phillips 66, including its subsidiary Phillips 66 Company: 154, 500, 501, 502, 506, 511, 512, 513, 514, 539, 544, 548, 549, 562, 570, 582, 592 and 593.

Schedule Page: 429 Line No.: 23 Column: c

Accounts charged for MEC: 426.5, 557, 580, 588, 920, 921, 923, 931 and 930.2.

Schedule Page: 429 Line No.: 24 Column: c

Accounts charged for NV Energy, Inc.: 408.2, 426.5, 920, 921, 922, 923 and 931.

Schedule Page: 429 Line No.: 26 Column: c

Non-power goods or services provided by Wells Fargo & Company for financial transactions related to energy hedging activity: 131, 232 and 547.

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